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ENVIRONMENTAL IMPACTS, EFFICIENCY, AND COST OF ENERGY SUPPLY AND END USE. VOLUME II

HITTMAN ASSOCIATES, INCORPORATED

PREPARED FOR
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ENVIRONMENTAL PROTECTION AGENCY
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16. Abstracts

The purpose of this study was to determine the environmental impacts, efficiency, and costs associated with supply and end use of fossil fuels. The output is this 2-volume report, which presents tabular, footnoted, and referenced data quantifying the energy-related environmental impacts on land, water, air, solid waste, and occupational health. All the information is also available in the form of a computerized data base, Matrix of Environmental Residuals for Energy Systems. Brookhaven created the data base and has written a number of data management and energy modeling programs, which with MERES are known as the Energy Model and Data Base. Vol. II characterizes six technologies with respect to their environmental impacts, efficiency, and cost: both low- and high-Btu gasification of coal, oil shale, fluidized bed boiler combustion, solvent refined coal, and coal liquefaction.

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VOLUME II FINAL REPORT

HIT-593

January 1975

Work Sponsored by

The Council on Environmental Quality,
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The Environmental Protection Agency

Contract EQC 308

HITTMAN ASSOCIATES, INC.
COLUMBIA, MARYLAND

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FOREWORD

The efforts represented by this two volume final report were begun in December 1972. A draft version of Volume I was issued September 1973 and the various sections of Volume II published in draft form between February and June 1974. Extensive revisions to the draft versions of this work have resulted in a two volume final report.

Impetus for the program was recognition of a need for an organized approach to the environmental impacts caused by energy supply and use. This study, building upon earlier work completed by the Council on Environmental Quality, provides a systematic technique for identifying environmental tradeoffs and problems associated with current energy scenarios. By offering an organized and consistent approach to environmental impacts, this report can lend a quantitative sophistication to policy discussion.

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This work has been sponsored by the Council on Environmental Quality, The Environmental Protection Agency, and the RANN Program of the National Science Foundation. The Atomic Energy Commission has contributed through support of the energy modeling efforts at Brookhaven National Laboratory (BNL). The data contained in this volume are being placed in a computerized information retrieval system at BNL, and computer programs are being written which will allow rapid analysis of the environmental effects of energy systems.

Contract monitoring and all technical coordination has been through the Council on Environmental Quality. We wish to thank Dr. Steve Rattien, Dr. Stephen Gage, and Mr. Marvin Singer of that office for their continued assistance and support in this effort. Their suggestions over the course of the program have created a more useful product.

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I. INTRODUCTION AND SUMMARY

This is Volume II of a two volume report which describes the results of a study performed by Hittman Associates, Inc. (HAI), and sponsored by the Council on Environmental Quality (CEQ), The Environmental Protection Agency, and The RANN Program of the National Science Foundation. The purpose of the study was to determine the environmental impacts, efficiency, and costs associated with the supply and end use of fossil fuels. The study builds upon preliminary work already completed by CEQ.

The output of the study takes two forms. This report presents tabular, footnoted, and referenced data quantifying the broad range of energy-related environmental impacts on land, water, air, solid waste, and occupational health. All of the information contained in this report is also available in the form of a computerized data base. This data base has been given the name MERES: Matrix of Environmental Residuals for Energy Systems. As part of an ongoing contract with the Atomic Energy Commission, Brookhaven National Laboratory has created the data base, and also has written a number of data management and energy modeling programs. These programs, together with the MERES data, are known as the Energy Model and Data Base (EMDB).

Environmental analyses of energy-related facilities have previously been incomplete. Among other things, these analyses typically considered only individual components, such as an isolated power plant, refinery, etc., and not entire energy systems.

The construction of a coal-fired power plant causes air, water, solid waste, and land impacts not only at the immediate site of the power plant, but also at the site where the coal is mined, washed, processed or prepared, and along the route that the coal is transported. The entire sequence of activities, from the mining of the coal to the production of electricity, and its end use in some home appliance or industrial process, is what is referred to as an energy system or "trajectory" and should be analyzed.

Similar trajectories or energy supply "chains" exist for oil production and refining. The construction of a refinery causes air and water pollutants, solid waste, and land disruption. However, additional environmental effects are felt at the point of crude oil production, during the crude and product transportation, and at the point of marketing and end use.

Using the data bank, it is possible to aggregate the environmental impacts of a wide variety of fossil fuel "trajectories" traced from the end use of a fuel to its extraction or vice versa.

This makes it possible to estimate environmental impacts for any number of scenarios related to energy consumption patterns envisioned for the next 10 to 20 years.

The objectives of the Phase I study reported in the companion Volume I are summarized in Figure 1. Tasks 1 and 2 are national in nature while Task 3 includes the impacts of regional energy supply subsystems. In all cases, the data have been developed for coal, oil, and natural gas. A more detailed breakdown of the regions covered in Task 3 is provided by Figure 2.

Thirty environmental impact tables are contained in Volume I. Twelve of these are devoted to coal supply, twelve to oil supply, one to natural gas supply, four to energy end uses, and one to the electric power plant activity of energy supply. Each entry in these tables is footnoted and referenced.

The objective of the Phase II study reported in this volume was to supplement the Phase I activities with various emerging energy technologies. Six technologies, shown in Figure 3, were characterized with respect to their environmental impacts, efficiency, and cost. These technologies represent additional links in the supply and end use chain of fossil fuels and are a necessary component of future energy investigations.

These six emerging technologies are in a state of rapid development. Characteristics of and emissions from these processes can be expected to change as more is learned from research and experimentation. Therefore, it is important to note the time frame of the data used in the tables and footnotes of this volume. Tasks 5, 6, and 7 (low Btu and high Btu gasification and oil shale) are based on data assembled in the Fall of 1973. Fluidized bed boiler combustion data (Task 8) was assembled in the early months of 1974. Data used in Tasks 9 and 10 (solvent refined coal and coal liquefaction) was collected in the Spring of 1974. More recent information may have been developed since this base data was assembled.

It must be noted that the environmental impacts reported herein only characterize the initial step in the environmental chain--that is, the amount of effluent discharged from the boundary surrounding a particular process or end use. The interaction of the outfall, air emission, land use, etc. with the biosphere is not included in this study.

TASK 1 EXTRACTION, PROCESSING, CONVERSION, AND DELIVERY OF FOSSIL FUEL ENERGY

- OBJECTIVE 1 - DETERMINE PROCESS EFFICIENCIES FOR FOSSIL FUEL PRODUCTION AND DELIVERY
- OBJECTIVE 2 - QUANTIFY ENVIRONMENTAL IMPACTS FOR EACH PROCESS, WITH PRESENT CONTROLS
- OBJECTIVE 3 - DETERMINE IMPACTS WITH CONTROL TECHNOLOGY AVAILABLE AND LIKELY TO BE IMPLEMENTED
- OBJECTIVE 4 - DETERMINE SYSTEM COSTS FOR UNCONTROLLED AND CONTROLLED ENERGY SUPPLY

TASK 2 END USES OF ENERGY

- OBJECTIVE 1 - DETERMINE ENERGY USE PER APPROPRIATE MEASURE OF USEFUL ACTIVITY
- OBJECTIVE 2 - DETERMINE ENVIRONMENTAL IMPACTS OF END USES

TASK 3 SENSITIVITY ANALYSIS OF TASK 1 DATA - REGIONAL STUDIES (BOTH UNCONTROLLED AND CONTROLLED)

Figure 1. Description of Phase I Study

COAL

- o NORTHWEST (POWDER RIVER BASIN)

  MONTANA & WYOMING; AREA STRIP

- o SOUTHWEST (FOUR CORNERS AREA)

  NEW MEXICO; AREA STRIP

- o CENTRAL

  ILLINOIS & INDIANA; AREA STRIP; ROOM & PILLAR DEEP

- o NORTHERN APPALACHIA

  NORTHERN W. VA., CENTRAL & W. PA.; CONTOUR STRIP, ROOM & PILLAR DEEP, LONGWALL DEEP

- o CENTRAL APPALACHIA

  EASTERN KY., TENN., SOUTHERN W. VA.; STEEP SLOPE CONTOUR STRIP, ROOM & PILLAR DEEP

OIL

- o DOMESTIC ON-SHORE
- o IMPORTED SOUTH AMERICAN RESIDUAL
- o IMPORTED MIDDLE EASTERN CRUDE
- o IMPORTED CANADIAN CRUDE
- o DOMESTIC OFF-SHORE

NATURAL GAS

- o DOMESTIC ON-SHORE
- o DOMESTIC OFF-SHORE
- o IMPORTED CANADIAN

Figure 2. Task 3 Regional Studies

TASK 5	LOW BTU GASIFICATION OF COAL
TASK 6	HIGH BTU GASIFICATION OF COAL
TASK 7	OIL SHALE
TASK 8	FLUIDIZED BED BOILER COMBUSTION
TASK 9	SOLVENT REFINED COAL
TASK 10	COAL LIQUEFACTION

Figure 3. Phase II Study Description

II. DATA BASE DESCRIPTION

A. Nomenclature

In order to describe a scenario dealing with environmental effects of energy, a number of definitions have been adopted:*

Term	Example/Definition
Element	SO_2 emission in transportation of coal by unit train
Process	Coal transportation by unit train (a set of elements)
Activity	Coal transportation (combination of a set of processes)
Trajectory	Coal in the ground to steel production by electric furnace (the set of linked activities which connect the supply of a specific resource with a specific end use)
Subsystem	Coal in the ground to any linked end use (a logical collection of trajectories defining an aspect of the total energy system)
System	Energy production and use in a given year (collection of all trajectories in the energy economy)

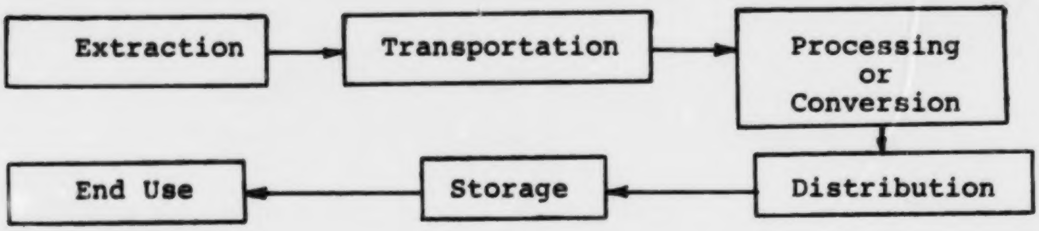
---

* These definitions are identical to those formulated by Brookhaven National Laboratory

These definitions are further explained by the following diagram:

TRAJECTORY

Sequence of Activities

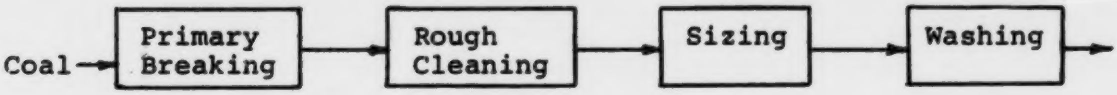

Extraction
Transportation
Processing or Conversion
Distribution
Storage
End Use

ACTIVITY

An activity is one or more processes.

One process could be distribution of coal by unit train.

Several processes in series might be as shown below.


Coal
Primary Breaking
Rough Cleaning
Sizing
Washing

The environmental impacts to be identified and quantified are those which relate to water pollution, air pollution, generation of solid wastes, use of land, occupational health, and potential for large scale disaster.

The water and air pollutants under consideration are the following:

Water:
- Acids
- Bases
- Dissolved solids - PO_4, NO_3, others
- Suspended solids
- Organics
- BOD
- COD
- Thermal

Air:

- Particulates
- NO_x
- SO_x
- Hydrocarbons
- CO
- Aldehydes, etc.

Solid wastes under consideration are all residuals not entering the air or water that result from the basic fuel resources or from the system processes that make fuels useful for consumption, or from the end use of fuels.

The land impacts include areas required for extraction, structures, disposal of solid wastes, roads, ports, pipelines, storage, and buffer zones. Both fixed and incremental land effects are considered. Fixed land effects are those associated with facilities such as processing plants, pipelines and storage tanks, whereas incremental land effects are those associated with excavation, such as strip mining, and solid waste disposal.

Occupational health is considered on the basis of deaths, injuries, and man-days lost due to injuries.

All of the environmental impacts mentioned so far are quantified and tabulated with suitable units. Further details are given in the following section on energy supply.

The potential for large scale disaster is identified with respect to the possible nature and magnitude of disasters and to specific processes in the supply and end-use trajectories. No quantifications are associated with these identifications.

B. Format

The construction of a computerized data bank requires that a large number of inputs be prepared according to a specific format. From the standpoint of this report, the reader need only be familiar with certain ground rules regarding data identification. The relationship between the format of data in this report and the computerized data bank is explained further in Section D.

1. Impact Data and Data Hardness

Each entry of environmental impact data in the supply tables has three parts. This is illustrated below.

2.40-04 3 7019

footnote number

data input hardness number

data input to three significant figures
2.40-04 is equivalent to 2.40x10^{-4} or
.000240. Units of the data are at the
top of the column in the table

A data hardness number is required for each entry except those with 0998 and 0999 footnote designations. In the computerized data bank, it will be possible to search for hardness numbers in order to categorize the inaccuracy of data blocks. Hardness number definitions are given in Figure 4. As a general rule, it is useful to consider data hardness in the context of "confidence" and relate this to the 1 to 5 scale.

Footnotes and References use abbreviations where possible to facilitate loading of data into the computer data bank. Appendix A is a list of abbreviations and their definitions. When using exponential numbers such as 1.35x10^8, the designation within the footnote will be 1.35E+08, 1.35E08, or 1.35+08.

2. Footnotes and References

Footnotes and references have been classified according to a numbering system which is shown in Figure 5. Note that specific blocks of numbers have been allocated to the various pieces of data assembled. The numbers in Figure 5 indicate which new footnotes follow each individual table. These footnotes are related to the new information generated for the table in question. This will become apparent as the tables are used. Footnote and reference numbers appearing in this volume but not included in Figure 5 are from Volume I of this report. Many of these footnotes and references have been included in this volume as well for convenience.

Hardness	Definition*	Example
1	Very Good - Highest confidence. Error probably ≤10 percent. Data well accepted and verified.	Nationwide consumption based on accurate reporting technique.
2	Good - Reputable and accepted. Error probably ≤ 25 percent.	Data from several major companies used to represent U.S.
3	Fair - Error probably ≤ 50 percent. Validity may be uncertain due to method of combining or applying data.	Data from one company used to represent U.S.
4	Poor - Low confidence in data. Error probably 100 percent. Validity questionable.	Telecon estimate used in absence of measurement.
5	Very Poor - Validity of data unknown. Error probably within or around an order of magnitude.	Assumption based on related reference. Several Fair or Poor sources combined.

---

* Error levels cited refer to cases where the data are non-zero. For zero or "negligible" values, the definitions Good, Fair, etc. should be applied to the various hardness levels.

Figure 4. Hardness Number Definitions

	Table No.	Footnote Numbers	Reference Numbers
Low Btu Coal Gasification	1	8000-8112	8000-8035
High Btu Coal Gasification	2	8300-8483	8300-8324
Oil Shale	3	9000-9105	9000-9041
Fluidized Bed Boiler Combustion	4	9200-9234	9200-9222
Solvent Refined Coal	5	9300-9350	9300-9335
Coal Liquefaction	6	9400-9460	9400-9406

Figure 5. Numbering Classification for Footnotes and References

In addition to the footnotes which are printed text, three other designations are used in the tables. These are defined as follows:

Footnote No.	Definition
0997	Zero or negligible impact for this activity - an appropriate hardness value is required
0998	This impact not applicable to this activity
0999	This value not available - an impact for this activity is assumed to exist

To simplify the citation of references within footnotes, the following format has been used:

Format for References in Footnotes:

(3004)	Reference 3004
(3004,739)	Reference 3004, page 739
(3004,739,742)	Reference 3004, pages 739,742
(3004,739/742)	Reference 3004, pages 739 through 742
(5123,A-9)	Reference 5123, page A-9
(5123,A-9,A-12)	Reference 5123, pages A-9, A-12
(5123,A-9/A-12)	Reference 5123, page A-9 through A-12

Note that a reference citation is always enclosed in parentheses.

Footnotes which follow the tables appear in the exact form that a computer printout will yield. Each footnote indicates the references and other footnotes it is based upon. In this report some minor inconvenience derives from having to refer to a separate list of references located following all of the tables and footnotes. However, in the computerized data bank, footnotes could be printed out followed immediately by the applicable references and first order footnote referrals.

C. Energy Supply

1. Introduction

The energy supply tables and footnotes deal with the quantification of the environmental impacts of each process in the fossil fuel energy supply trajectories based on a process input of the fuel equivalent to 10^{12} Btu/yr. The value of 10^{12} Btu/yr was chosen as a convenient unit for an energy rate. The rate form was chosen to facilitate the use of published data on environmental impacts in which a time factor is involved, such as, for example, emission rates in lb/day for evaporation losses from gasoline storage tanks, impacts related to annual production rates, etc.

Whereas Volume I to this report considered the supply trajectories of the primary fossil fuels and their derivatives, this volume focuses on six emerging energy technologies as components of future energy supply trajectories. Five of the six technologies - low Btu gasification, high Btu gasification, fluidized bed boiler combustion, solvent refined coal, and coal liquefaction - utilize coal in the production of synthetic fuels or electricity. The sixth, oil shale technology, considers the production of crude oil from this new energy source.

For those technologies utilizing coal, the environmental impacts, efficiencies, and costs have been developed for three regional coals and a national average case. In contrast to Volume I of this report, all of this information appears on the same table. The coals for which data have been developed include a low sulfur (Northwest), medium sulfur (Northern Appalachia), and high sulfur (Central) coal.

Each of the tables is organized as a matrix with the environmental impacts as columns and activities and processes as rows. For each activity on the left of the table, the relevant processes are listed immediately below. In general, the entries in the tables are on a process basis, rather than on an activity basis. As noted earlier, an activity may consist of a single process, or it may consist of a number of processes.

Each table has a related general footnote which gives basic data pertinent to the fuel considered, such as the amount of the fuel equivalent to 10^{12} Btu. It is important to note that all impacts have been derived for a process input of fuel equivalent to 10^{12} Btu/yr. In particular, for the extraction activity, this is interpreted to mean 10^{12} Btu of resource in the ground. Thus impacts for the extraction activity are expressed per 10^{12} Btu in the ground and not per 10^{12} Btu produced or extracted (output of fuel).

A general caution is applicable to all the supply data. Before using any impact expressed in terms of 10^{12} Btu, the reader should read the footnote. Potential misuses of the data can readily be cited. Increasing the plant capacity may not increase the land impact proportionately, since the land use is not necessarily linearly related to the productive capacity of the plant. Doubling the productive capacity doubles the land requirement only if an additional and identical facility is constructed. Caution must be exercised when evaluating the land effects for large multiples of 10^{12} Btu/yr. Similarly, size considerations are important in cost calculations and the footnote will relate how the particular entry has been calculated.

It is important to note the interrelationships between environmental impacts, efficiency, and cost data. Strictly speaking, a specified level of environmental control has associated with it corresponding levels of cost and energy requirements. This is apparent in a comparison of the uncontrolled and controlled environmental tables. However, this is also true within each supply table, as air pollutant data is related to ancillary fuel use, land use is related to solid waste data, etc. Air pollutants associated with the generation of electricity are ascribed to the power plant activity and not at the site of the process which uses the electricity as ancillary fuel.

2. Definition of Uncontrolled and Controlled

All supply tables are designated either controlled or uncontrolled. "Uncontrolled," according to the ground rules adopted in this study, means that impacts are the current national or regional average value. In the absence of current (1972-73) data, impacts typify the use of least stringent environmental controls.

"Controlled" implies that impacts are consistent with the use of control technology which will probably be required and/or available in 5 to 10 years. As an illustration, present laws governing the reclamation of surface mined lands minimally require that effort be made to restore the land. This may include partial backfilling and an attempt at revegetation. However, since the degree and success of reclamation are not mandatory, (for the "uncontrolled" condition) reclamation is not assumed for area stripping operations, and only partial backfilling is assumed for contour mines. In the controlled situation, contour backfilling and revegetation are required for either type of stripping operation. The attainment of this high level of reclamation would require such practices as stockpiling and redistribution of the topsoil, segregation of toxic overburden and seed bed preparation. Generally speaking, the controlled condition incorporates the environmental standards proposed or soon to be implemented by the

Environmental Protection Agency. A more detailed explanation of controlled and uncontrolled as it is related specifically to each process in the fossil fuel supply chain is to be found in the writeups preceding each of the supply tables and in the accompanying table footnotes.

The data in this volume have all been developed for the "controlled" environmental condition. This was because the technologies considered herein are either being developed primarily for environmental control or are potentially major contributors to environmental impact. For this latter category, from a practical point of view, stringent environmental controls will be a necessity.

3. Environmental Parameters

In the supply tables, the units for the various environmental impacts are noted above the columns. Since the basis for the tables is the fuel equivalent of 10^{12} Btu/yr, the actual units for the values given in the tables are interpreted as follows:

Water Pollutants:

Acids, bases, dissolved solids, suspended solids, organics:

$$\frac{\text{Tons discharged to water bodies/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{tons}}{10^{12} \text{ Btu}}$$

BOD, COD:

$$\frac{\text{Oxygen demand in tons/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{tons}}{10^{12} \text{ Btu}}$$

Thermal:

$$\frac{\text{Btu discharged to water bodies/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Btu}}{10^{12} \text{ Btu}}$$

Air Pollutants:

$$\frac{\text{Tons discharged to atmosphere/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{tons}}{10^{12} \text{ Btu}}$$

Solid Waste:

$$\frac{\text{Tons placed on land/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{tons}}{10^{12} \text{ Btu}}$$

Occupational Health:

Deaths:

$$\frac{\text{Deaths/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Deaths}}{10^{12} \text{ Btu}}$$

Injuries:

$$\frac{\text{Serious injuries/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Serious injuries}}{10^{12} \text{ Btu}}$$

Man-days lost:

$$\frac{\text{Man-days lost due to serious injuries/yr}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Man-days lost}}{10^{12} \text{ Btu}}$$

Land:

Fixed:

$$\frac{\text{Acres occupied by fixed facilities}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Acre-yr}}{10^{12} \text{ Btu}}$$

Incremental:

$$\frac{\text{Time-averaged incremental acres}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr}} = \frac{\text{Acre-yr}}{10^{12} \text{ Btu}}$$

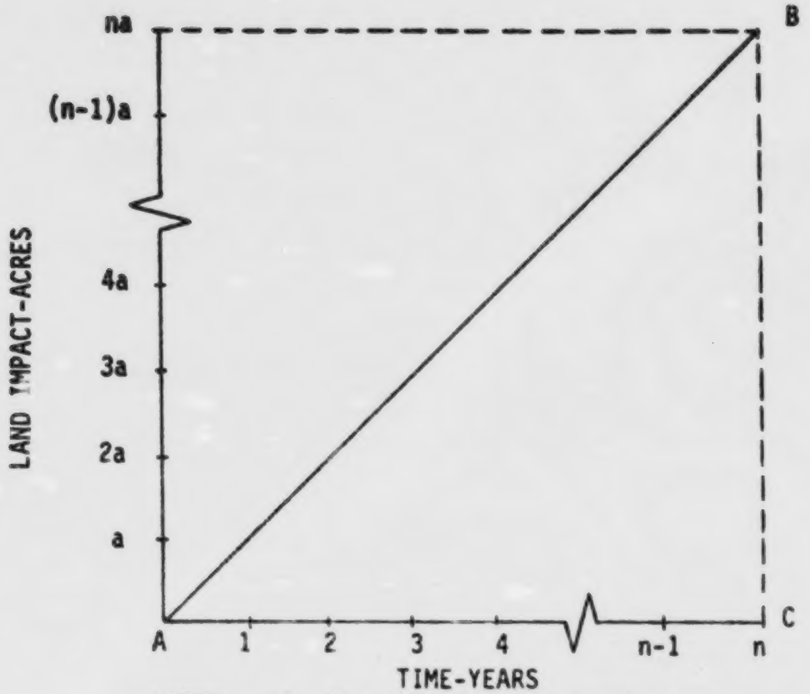
The values for land disturbed shown in the tables are, where applicable, the sum of fixed and time averaged incremental land impacts. As an example, consider a coal processing plant which handles B Btu/yr of coal, occupies A acres, and produces solid waste for disposal occupying an additional a acres/yr. The fixed land impact is defined as:

$$A_f = \frac{A}{B} \text{ in units of } \frac{\text{acre- yr}}{10^{12} \text{ Btu}}$$

The incremental land impact is defined as:

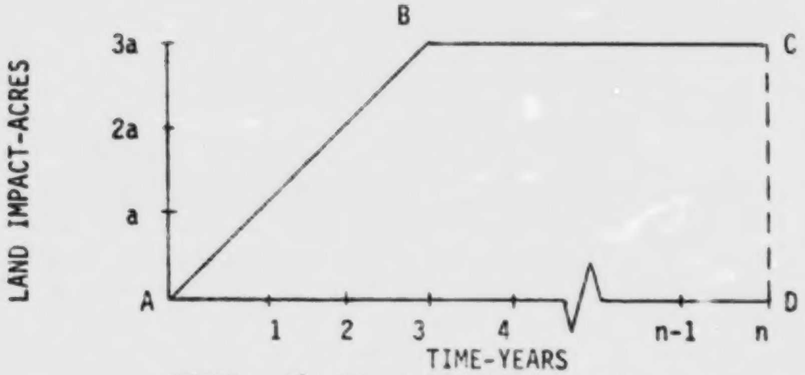
$$A_i = \frac{a}{B} \text{ in units of } \frac{\text{acre}}{10^{12} \text{ Btu}}$$

To sum these land impacts it is first necessary to introduce the units of time, or time average the incremental land impact. Conceptually this represents the average acres of land which will be impacted over the lifetime of the plant. Numerically, the time averaging process will depend on whether or not environmental controls, specifically reclamation of the disturbed land, will be employed. Figures 6 and 7 illustrate the uncontrolled (i.e., unreclaimed) and controlled (reclaimed) environmental conditions as they pertain to the time averaging of incremental land



NOTES: 1) Plant lifetime n years
2) Incremental land impact a acres/yr
3) No reclamation of disturbed land

Figure 6. Uncontrolled Incremental Land Impact



NOTES: 1) Plant lifetime n years
2) Incremental land impact a acres/yr
3) Reclamation of disturbed land with 3 year time lag for revegetation

Figure 7. Controlled Incremental Land Impact

use. As shown in Figure 6, for the uncontrolled plant with an n year lifetime and an incremental land impact of a acres/yr, the total amount of land disrupted after n years would be na acres since the land is not being reclaimed for use. The average land impact over the n year lifetime of the plant is given mathematically by the area of triangle ABC divided by n years, i.e. $\frac{1/2\ (n)(na)}{n}$ or $\frac{(n)}{2}$ a. Hence, the time averaged incremental land impact for the uncontrolled case is defined as:

$$A_{it} = \frac{n}{2}\ \frac{a}{B} \text{ in units of } \frac{\text{acre-yr}}{10^{12}\ \text{Btu}}$$

Figure 7 shows the land impact for the same plant employing reclamation practices to recover the land disrupted by the solid waste. In this example three years was chosen as the time period necessary for reestablishing vegetation. Thus, assuming concurrent reclamation, the land impact curve in Figure 7 levels off after the third year. That is, after the third year, the number of acres impacted remains constant. For each a acres disrupted in any year, an equivalent a acres has been reclaimed (starting three years before). The average land impact over the n year lifetime of the controlled plant would then be given mathematically by area ABCD divided by n years, i.e.,

$$\frac{(1/2(3)3a)\ +\ (3a)(n-3)}{n} \text{ or } (3-\frac{9}{2n})a.$$

Hence the time averaged incremental land impact for the controlled case with a three year time lag for revegetation is defined as:

$$A_{it} = (3-\frac{9}{2n})\ \frac{a}{B} \text{ in units of } \frac{\text{acre-yr}}{10^{12}\ \text{Btu}}\ .$$

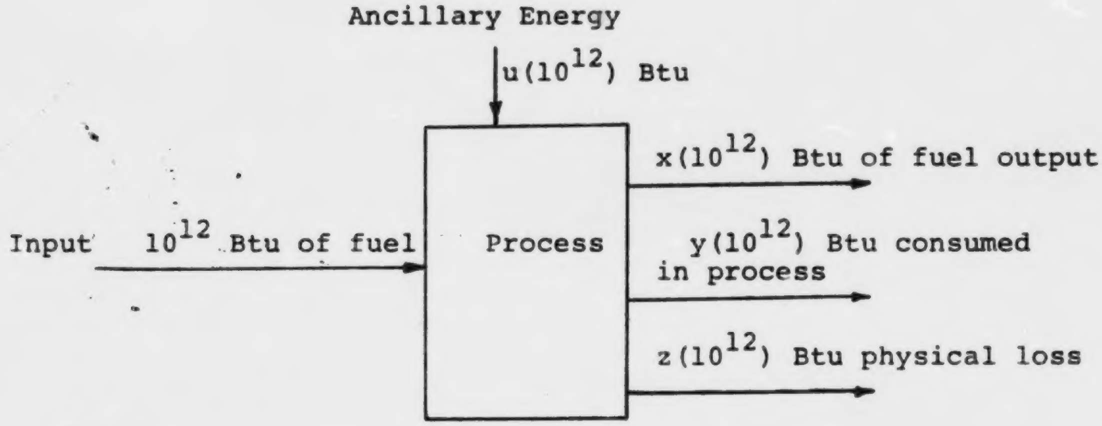
Note that the controlled definition given above is only applicable for those cases where three years is required for reestablishing vegetation. If this time lag changes, obviously so will the time averaging multiplier. Generally the plant lifetime (n) is taken as 25 years. Based on this value the time averaging multiplier for the uncontrolled case $(\frac{n}{2})$ would be 12.5 years, and for the three year time lag controlled case $(3-\frac{9}{2n})$, the multiplier would be 2.82 years.

This time averaged incremental land impact calculation arbitrarily ignores any land impact which could occur beyond the specified lifetime of the facility. Continuing impact from yet unreclaimed land or the remaining structural facilities beyond the expected useful life (n) of those facilities is not considered.

4. Efficiency

The Hittman data tables contain two efficiency related inputs. These are primary efficiency (column 26) and ancillary energy (column 27).

Efficiency definitions can be related to the following diagram:


Ancillary Energy
u(10^12) Btu
x(10^12) Btu of fuel output
Input 10^12 Btu of fuel
Process
y(10^12) Btu consumed in process
z(10^12) Btu physical loss

Where:

$x+y+z = 1$

Primary Efficiency $= x = 1-y-z$

Overall Efficiency $= x-u$ (BNL)

Overall Efficiency $= \frac{x}{1+u}$ (Theoretical)

$$x-u \cong \frac{x}{1+u} \text{ for small } u\text{, i.e., } u \ll 1$$

If the process separates the input fuel stream into several output fuels, $x(10^{12})$ may be taken as the sum of the energy contents of the output fuels and x as an approximate value for the efficiency of each output fuel.

In some processes there is apt to be confusion as to whether an energy use is classified as ancillary or part of the input flow consumed. In a refinery, refinery gas (which provides energy for many processes) is considered as primary fuel consumed rather than as an ancillary demand. Any use of a fuel derived from the primary input stream remains part of the primary flow.

5. Costs

Cost data expressed in 1972 dollars are included in the uncontrolled and controlled national supply tables in columns 28-30. The total capital or fixed cost for equipment, structures, etc. is annualized at 10 percent per year and shown in column 28. This capital "cost" is synonomous with total capital investment and does not include interest during development or working capital. Yearly operating expenses for fuels, maintenance, labor, etc. are given in column 29, while column 30, which represents the total annual cost, is the sum of columns 28 and 29. The units for the economic data are shown below:

$$\text{Fixed Cost:} \quad \frac{(\$ \text{ of capital expense}) \times (.10/\text{yr})}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr input}} = \frac{\$}{10^{12} \text{ Btu}}$$

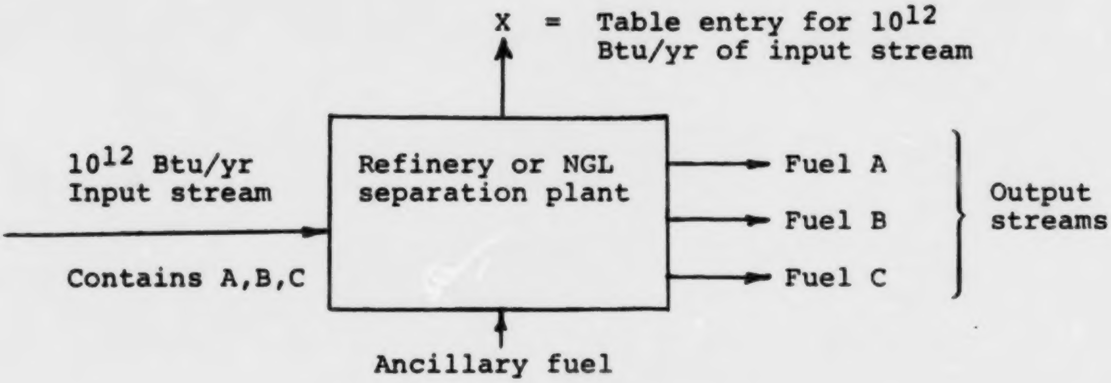
$$\text{Operating Cost:} \quad \frac{\$/\text{yr for operating expenses}}{\text{Fuel equivalent to } 10^{12} \text{ Btu/yr input}} = \frac{\$}{10^{12} \text{ Btu}}$$

The 10 percent/yr annualization or "fixed charge rate" (as it is called in the table footnotes) for capital expenses was chosen mainly for convenience and may or may not reflect actual practice within a particular industry. It is convenient to express the capital cost data in this fashion because: 1) it provides some estimate of total annual costs and 2) it allows a quick estimate of total capital cost from the table data by simply increasing the fixed cost by a factor of ten. That is, for a table fixed cost entry of 1.50+05, the total capital cost is 1.50+06 or 1-1/2 million dollars/10^{12} Btu equivalent fuel input.

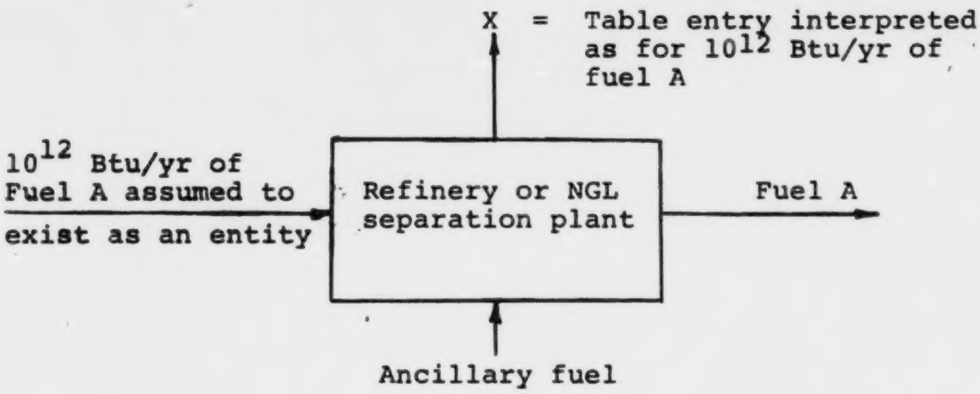
The price of the raw energy resource into a process is not included in any of the cost data. The annual cost data represented in the tables is a major component of the ultimate price level of the fossil fuels delivered. Since the basis for costs is 1972 dollars, table values would have to be adjusted to reflect present-day (1974) costs.

6. Allocation of Table Entries to Process Fuels

The following suggests a technique for allocating tabular impacts to the product fuel mix. A refinery or natural gas processing plant is used as an example. Oil refineries and natural gas processing plants separate input fuel streams into several output fuel streams.


X = Table entry for 10^{12} Btu/yr of input stream
10^{12} Btu/yr Input stream
Contains A,B,C
Refinery or NGL separation plant
Fuel A
Fuel B
Fuel C
Output streams
Ancillary fuel

If the data are to be used to construct a trajectory for a particular product fuel, starting at the well head where such fuel does not exist as an entity, the table entries for the processing activity or for activities prior to processing may be used as reasonable approximations for such product fuel.


X = Table entry interpreted as for 10^{12} Btu/yr of fuel A
10^{12} Btu/yr of Fuel A assumed to exist as an entity
Refinery or NGL separation plant
Fuel A
Ancillary fuel

D. Energy Model and Data Base (EMDB)

The data presented in this report have been entered in a computerized data base (MERES). Brookhaven National Laboratory has combined this data base with a number of data management and energy modeling programs to form a complete package known as the Energy Model and Data Base, or EMDB. Brookhaven National Laboratory (BNL) will continue to update, maintain, and improve the data base and its associated programs.

The EMDB is presently available on the Control Data Corporation computer facility at BNL. It will be directly accessible via a telephone connection and terminal to remote users. In writing the computer programs for the EMDB, care has been taken to insure that the programs would be easily transferrable to other computer facilities.

The basic unit of storage in the EMDB is a particular supply or utilization (end use) process, which corresponds to the complete set of numeric values contained in a single row of the tables in this report. Each basic process storage unit contains all of the numeric values (and their hardness factors) as well as the full documentation for the number set. The specific process desired is identified by a string of mnemonics which have different forms for supply and utilization processes. These string forms are as follows:

SUPPLY: /RESOURCE/ACTIVITY/PROCESS/REGION/CONTROL/.

UTILIZATION: /SECTOR/ACTIVITY/PROCESS/FUEL/CONTROL/.

The mnemonics for each supply activity and process can be found in the left-most column of each supply table (Tables 1-6). There are no utilization (end use) tables in this Volume. The accessing codes for supply are further detailed in Figure 8.

One of the programs associated with the EMDB permits the calculation of national energy flows and the impacts of such flows on resource consumption, pollutant emissions, and dollar costs. This program, called the Energy System Network Simulator (ESNS), considers the energy system as a set of process links in a network representation. These network process links can be associated with particular process blocks (both supply and utilization) in the EMDB. An interfacing program is provided which draws numeric values from the data base and makes them available for flow calculation through the network. Capabilities are also provided for modifying any numeric value for input to the ESNS and for adding new links to the ESNS network. With these capabilities, the effects of various simulation scenarios can be calculated.

Order of mnemonic string identifier corresponding to a supply table row:

/RESOURCE/ACTIVITY/PROCESS/REGION/CONTROL/.

Identifier		Mnemonic	
Resource:	Coal	COAL	
	Oil	OIL	
	Natural Gas	GAS	
Activity:		(See Supply Table)	
Process:		(See Supply Table)	
Region:	National	NATL	Coal
	Northwest	NW	
	Southwest	SW	
	Central	CNTRL	
	Northern Appalachia	NAPPL	
	Central Appalachia	CAPPL	
	Domestic Onshore	ONSHR	Oil
	Domestic Offshore	OFSHR	
	Imported Middle East Crude	MECRD	
	Imported Canadian Crude	CANAD	
	Imported South American Residual	SARSD	
	Onshore	ONSHR	Gas
	Offshore	OFSHR	
	Canadian	CANAD	
Control:	Controlled	CONTL	
	Uncontrolled	UNCON	

Figure 8. Data Access Code for Supply

III. LOW BTU GASIFICATION OF COAL

A. Introduction

The environmental impacts, efficiencies, and costs of Low Btu Gasification of Coal are given in Table 1 of this report. This table is based on an energy input of 10^{12} Btu/yr into each process utilizing current or soon to be available pollution control techniques.

The primary purpose of Low Btu Gasification of Coal is to provide fuel gas, ranging from 150-200 Btu/SCF, for power generating purposes. Although this low Btu gas may have other industrial purposes, this report assumes all gas is used to fire conventional or combined cycle power plants.

The five specific processes studied are:

1. Applied Technology Corporation (ATC) Process
2. Bureau of Mines Atmospheric Process
3. Bureau of Mines Pressurized Process
4. Lurgi Process
5. Koppers-Totzek Process

Each of the five technologies will consist of two activities; gasification and electricity generation. An electrical transmission activity is presented for the Northwest, Northern Appalachian and National Average cases. The transmission distances are based on the mileage from the generating location at the mine mouth to the metropolitan Chicago area. No electrical transmission data are presented for the Central case, since the gasification/electricity generation activities are assumed to take place in the metropolitan Chicago area.

The environmental impacts in Table 1 are based on processing three regional coals and a simulated national average coal. It should be noted that all capital costs shown in Table 1 are based on a plant load factor of unity, i.e., the plant is assumed to operate 365 days/yr. The values presented in this table are based on data accumulated during the Fall of 1973.

The following is a brief description of the individual processes:

ATC - SO_2 Free Two-Stage Coal Combustion Process

The ATC process (Figure 9) consists of injecting coal particles into a molten bath of iron. Because iron in the liquid state has an affinity for sulfur and carbon, the coal solubilizes to release organic and inorganic sulfur constituents for reaction with the active iron melt. The iron sulfides formed migrate to a lime containing slag floating on the molten iron bath where they are removed from the combustion process. At the same time, the carbon that is dissolved in the molten iron is reacted with air to produce an off-gas which consists of nitrogen, carbon monoxide, and hydrogen. This 2500°F+ gaseous mixture, essentially free of sulfur dioxide, is introduced into a steam boiler along with secondary air to recover all of the heating value of the coal. Sulfur is recovered in elemental form from the slag produced in the ATC process, along with iron contained from the coal pyrites and a desulfurized slag.

Bureau of Mines - Producer Gas at Atmospheric Pressure

The Atmospheric Pressure Producer Gas Process (Figure 10) consists of gasification of coal by its partial combustion in a stirred bed, supported on a revolving eccentric grate which removes the ash. The raw producer gas is passed through iron oxide absorbers for sulfur removal. The regenerated absorbers yield sulfur dioxide which flows to an ammonium sulfate plant for the production of crystallized ammonium sulfate. The desulfurized atmospheric producer gas coming off the iron oxide absorbers contains soot and tars and is at approximately 1300°F.

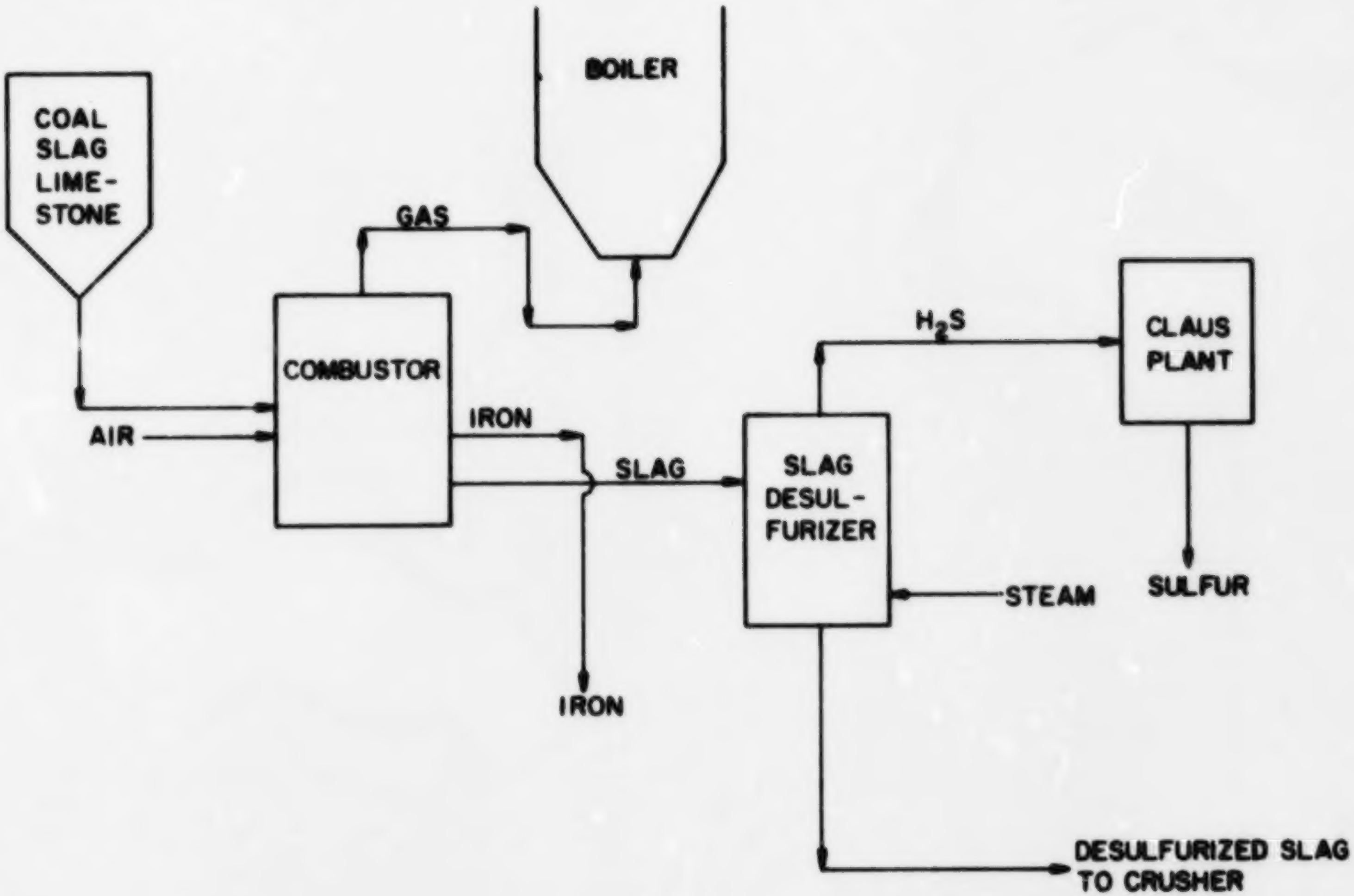

COAL
SLAG
LIME-
STONE
BOILER
GAS
COMBUSTOR
AIR
IRON
SLAG
IRON
SLAG
DESUL-
FURIZER
H_2S
CLAUS
PLANT
STEAM
SULFUR
DESULFURIZED SLAG
TO CRUSHER

Figure 9. Applied Technology Corporation Two-Stage Combustion Process for Low Btu Coal Gasification (Ref. 8022)

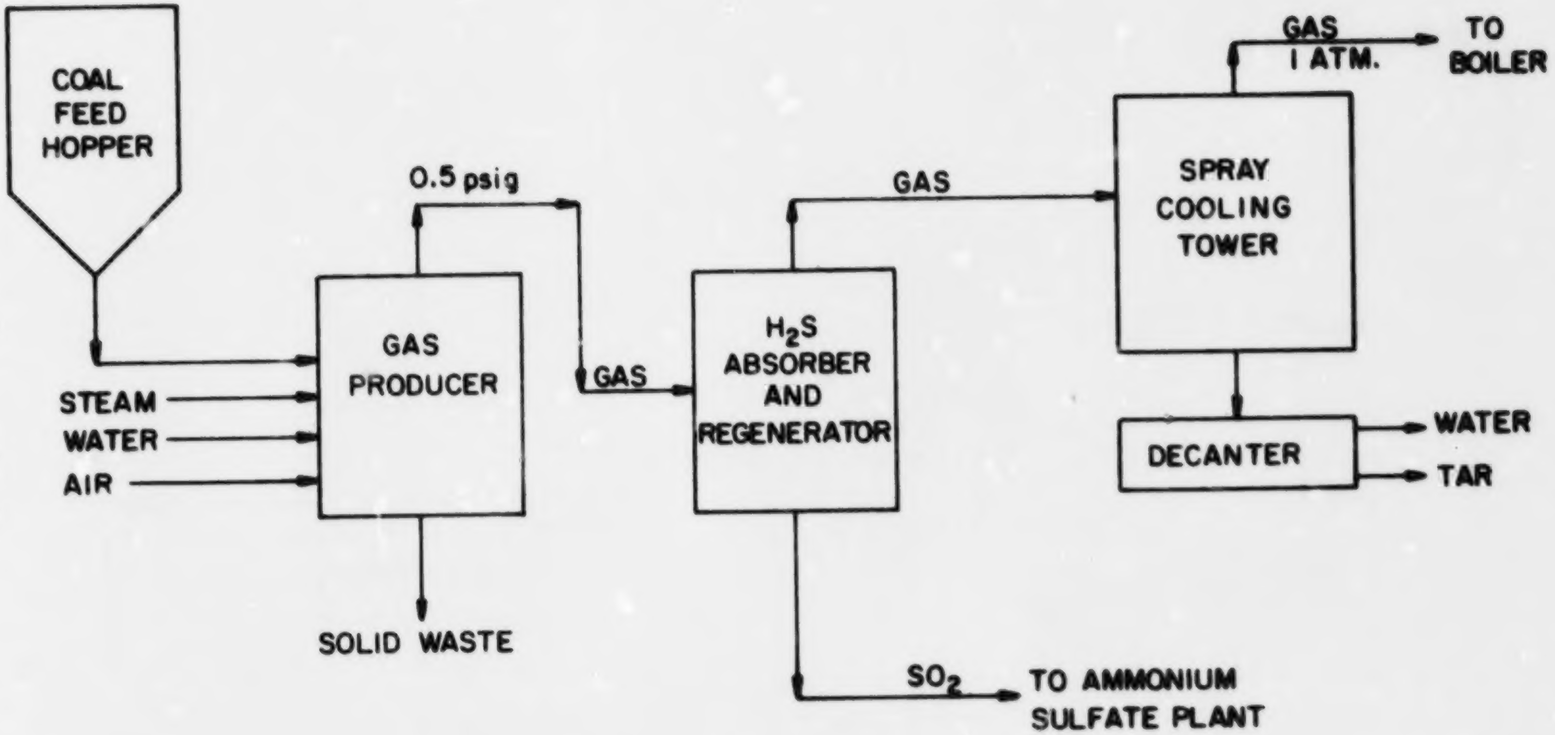

COAL FEED HOPPER
STEAM
WATER
AIR
GAS PRODUCER
SOLID WASTE
0.5 psig
GAS
H_2S ABSORBER AND REGENERATOR
SO_2
TO AMMONIUM SULFATE PLANT
GAS
SPRAY COOLING TOWER
GAS 1 ATM.
TO BOILER
DECANTER
WATER
TAR

Figure 10. Bureau of Mines Atmospheric Gas Producer for Low Btu Coal Gasification (Ref. 8014)

Bureau of Mines - Producer Gas at Elevated Pressures

The Elevated Pressure Producer Gas Process (Figure 11) consists of gasification of coal in the same manner as described for the Atmospheric Producer Gas Process, with the important exception that the producer vessel is pressurized to 120 PSIG. To accomplish this,coal is fed to the producer vessel through a lock hopper system. The gas coming off the iron oxide absorbers flows to the gas scrubbers where soot and tars are removed. This will allow the 270°F, 120 PSI product gas to be utilized in a gas turbine for combined cycle power generation.

Lurgi Process

The Lurgi Process (Figure 12) consists of gasification of coal with air and steam at a pressure of 300 PSI. The gas leaving the gasifier is scrubbed to remove coal dust, alkali and chlorine. The H_2S is then removed from the gas stream by an alkalized wash. Subsequently the H_2S is converted into elemental sulfur in a Claus kiln. The gas produced contains oil, naptha vapor and other carbon products of the gasified coal and is at a temperature and pressure of 300°F and 250 PSI respectively.

Koppers-Totzek Process

The Koppers-Totzek Process (Figure 13) consists of the partial oxidation of pulverized coal in suspension with oxygen and steam. The heart of the process is the burner nozzles at which the oxygen, steam and coal react to gasify the carbon and volatile matter of the coal at a slight positive pressure and at 330°F. After gas cooling and scrubbing, the gas stream is desulfurized. The gas produced will be at less than 350°F and slightly greater than atmospheric pressure.

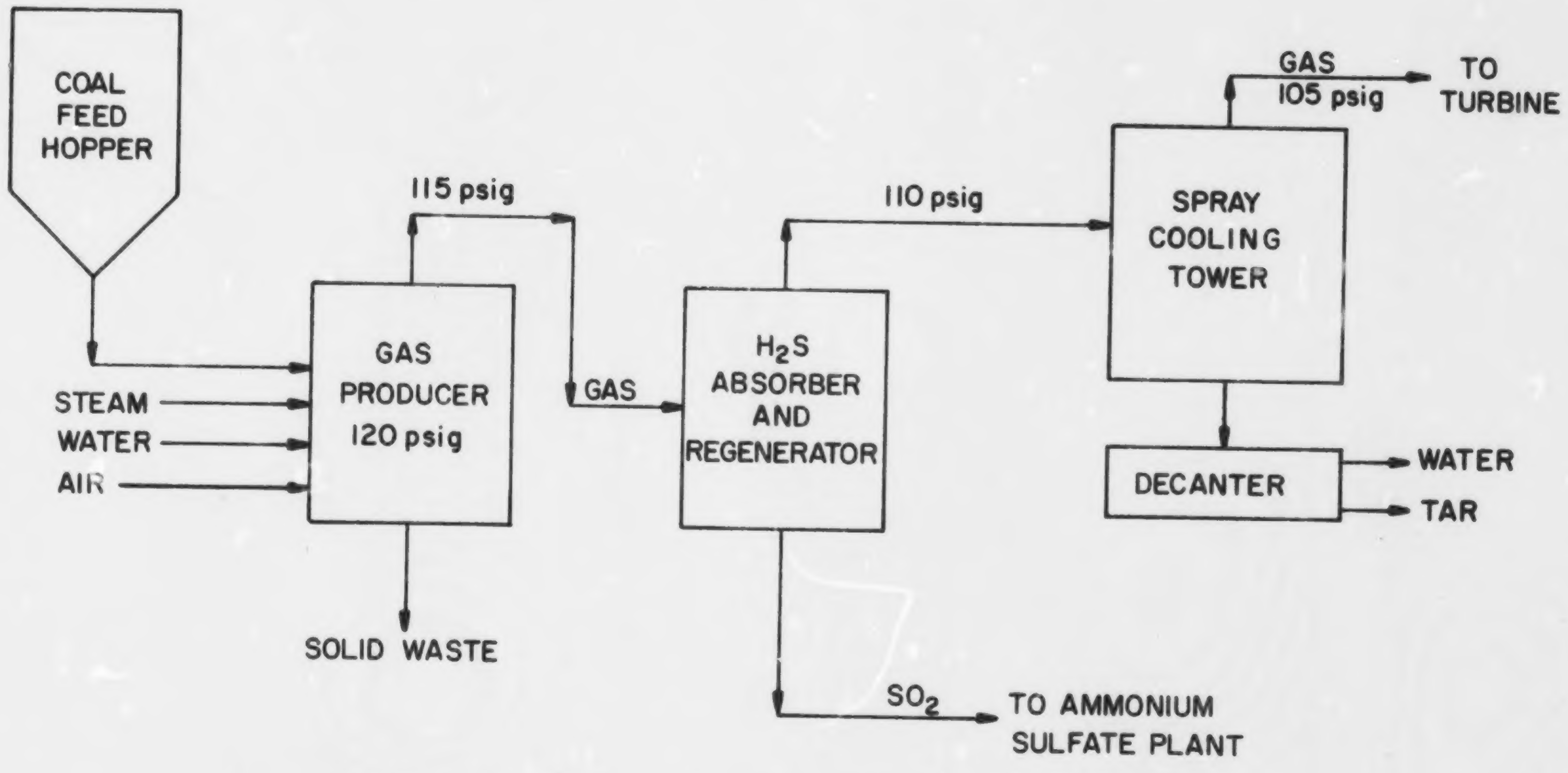

COAL FEED HOPPER
STEAM
WATER
AIR
GAS PRODUCER 120 psig
115 psig
GAS
SOLID WASTE
H_2S ABSORBER AND REGENERATOR
110 psig
SO_2
TO AMMONIUM SULFATE PLANT
SPRAY COOLING TOWER
GAS 105 psig
TO TURBINE
DECANTER
WATER
TAR

Figure 11. Bureau of Mines Pressurized Gas Producer for Low Btu Coal Gasification (Ref. 8014)

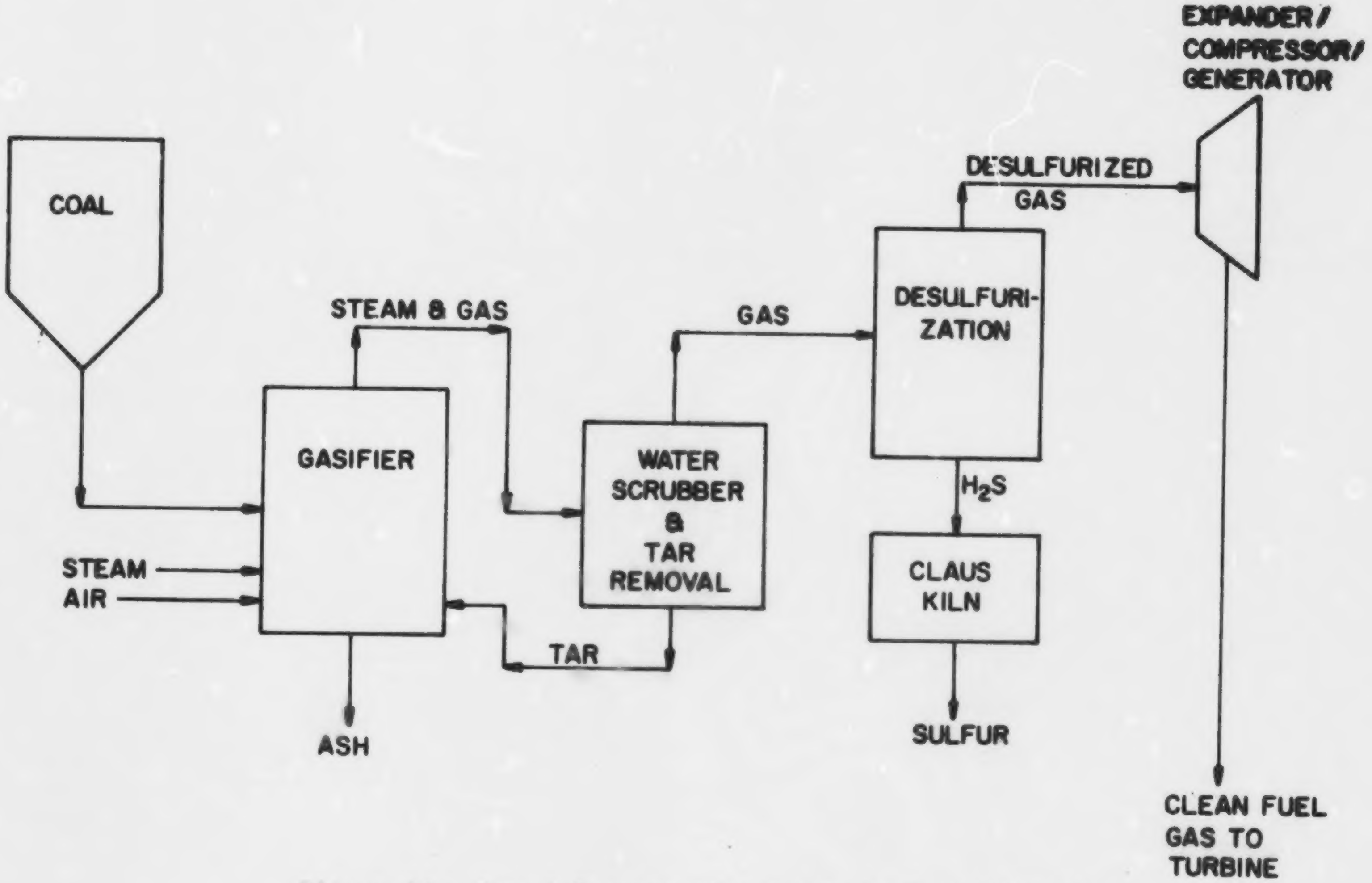

EXPANDER/
COMPRESSOR/
GENERATOR
COAL
DESULFURIZED
GAS
DESULFURI-
ZATION
STEAM & GAS
GAS
GASIFIER
WATER
SCRUBBER
&
TAR
REMOVAL
H_2S
STEAM
AIR
CLAUS
KILN
TAR
ASH
SULFUR
CLEAN FUEL
GAS TO
TURBINE

Figure 12. Lurgi Process of Low Btu Coal Gasification
(Ref. 8031)

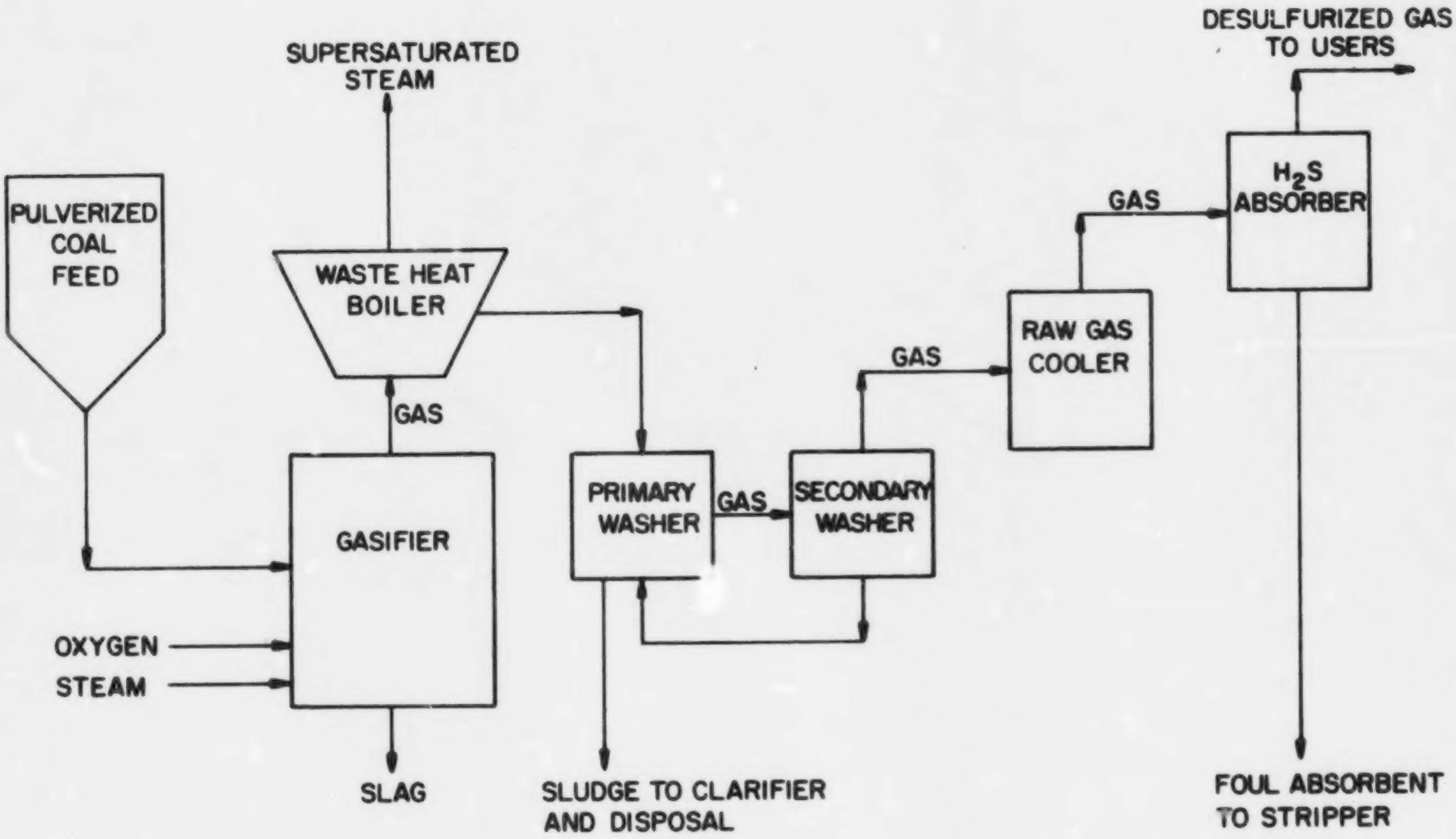

SUPERSATURATED STEAM
DESULFURIZED GAS TO USERS
PULVERIZED COAL FEED
WASTE HEAT BOILER
GAS
H_2S ABSORBER
GAS
RAW GAS COOLER
GAS
GAS
PRIMARY WASHER
SECONDARY WASHER
GASIFIER
OXYGEN
STEAM
SLAG
SLUDGE TO CLARIFIER AND DISPOSAL
FOUL ABSORBENT TO STRIPPER

Figure 13. Koppers-Totzek Process of Low Btu Coal Gasification (Ref. 8024)

B. Impact Data Table and Footnotes

CONTROLLED	
FUEL	REGION
COAL	AS INDICATED

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX COL 12)												AIR POL		
ROW	MNE-MON	ACTIVITY PROCESS	ACIDS	BASES	DISSOLVED SOLIDS				SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO$_x$	SO$_x$
					PO$_4$	NO$_3$	OTHER	TOTAL (DS)									
1		CENTRAL															
2	CASLO	LOW BTU GASIFICATION															
3	ATCCO	ATC COMBUSTOR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4	BOMAT	BOM ATMOSPHERIC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5	BOMPR	BOM PRESSURIZED	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	KOPTK	KOPPERS TOTZEK	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7	ELCEN	ELECTRICITY GENERATION															
8	ATCBL	ATC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	BOMAB	BOM ATMOSPHERIC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	BOMPC	BOM PRES. COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	KOPTK	KOPPERS-TOTZEK COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	TRANS	TRANSMISSION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13																	
14		NORTHERN APPALACHIA															
15	CASLO	LOW BTU GASIFICATION															
16	ATCCO	ATC COMBUSTOR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	BOMAT	BOM ATMOSPHERIC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	BOMPR	BOM PRESSURIZED	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19	KOPTK	KOPPERS TOTZEK	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	ELCEN	ELECTRICITY GENERATION															
21	ATCBL	ATC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
22	BOMAB	BOM ATMOSPHERIC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
23	BOMPC	BOM PRES. COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	KOPTK	KOPPERS-TOTZEK COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
25	TRANS	TRANSMISSION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26																	
27		NORTHWEST															
28	CASLO	LOW BTU GASIFICATION															
29	ATCCO	ATC COMBUSTOR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
30	BOMAT	BOM ATMOSPHERIC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
31	BOMPR	BOM PRESSURIZED	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
32	LURG	LURGI	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
33	KOPTK	KOPPERS TOTZEK	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
34	ELCEN	ELECTRICITY GENERATION															
35	ATCBL	ATC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
36	BOMAB	BOM ATMOSPHERIC BOILER	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
37	BOMPC	BOM PRES. COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
38	LURCC	LURGI COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
39	KOPTK	KOPPERS TOTZEK COMB. CYC.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
40	TRANS	TRANSMISSION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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HITTMAN

12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10¹² BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10¹² BTU)			
THERMAL BTU/10¹² BTU	PARTICULATES	NOx	SOx	HYDROCARBONS	CO	ALDEHYDES ETC.	TOTAL	SOLIDS TONS/10¹² BTU	LAND (ACRE-YR / 10¹² BTU)	DEATHS / 10¹² BTU	INJURIES / 10¹² BTU	MAN-DAYS LOST/10¹² BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY BTU/10¹² BTU	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
																			2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	7.88-01 1 8068	3.59+09 3 8086	4.70-04 3 8092	0999	0999	3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	7.83-01 2 8083	3.23+10 3 8042	[illegible]	5.77-04 3 8098	9.20-04 3	4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	7.35-01 2 8079	[illegible]	8.23-04 3 8094	1.35-05 3 8097	2.17-05 3	5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	1.36+05 3 8095	0999	0999	6
																			7
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	3.80-01 2 1912	3.37+09 4 8089	1.41-05 2 8112	6.79-04 2 2907	2.09-05 2	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	3.80-01 2 1912	[illegible]	1.41-05 2 8112	6.79-04 2 2907	2.09-05 2	9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	4.00-01 2 8065	4.74+09 4 8062	1.53-05 3 8091	0999	0999	10
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	[illegible]	1.53-05 3 8091	0999	0999	11
0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	12
																			13
																			14
																			15
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	1.59+09 3 8086	[illegible]	0999	0999	16
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	17
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	7.48-04 3 8094	[illegible]	1.94-05 3	18
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	0999	0999	19
																			20
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	3.80-01 2 1912	3.37+09 4 8089	[illegible]	[illegible]	[illegible]	21
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	3.80-01 2 1912	[illegible]	[illegible]	[illegible]	[illegible]	22
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	4.00-01 2 8065	4.74+09 4 8062	[illegible]	0999	0999	23
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	4.74+09 4 8062	[illegible]	0999	0999	24
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	5.12-01 2 1913	0999	0999	0999	0999	25
																			26
																			27
																			28
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	0999	0999	29
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	7.31-01 2 8085	[illegible]	[illegible]	7.58-04 3 8098	1.23-05 3	30
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	1.76-05 3 8097	[illegible]	31
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	32
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	[illegible]	[illegible]	[illegible]	0999	0999	33
																			34
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	35
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	36
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	4.00-01 2 8065	[illegible]	1.53-05 3 8091	0999	0999	37
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	[illegible]	[illegible]	0999	0999	38
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	[illegible]	[illegible]	[illegible]	0999	0999	39
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0999	0999	0999	0999	4.12-01 2 1913	0999	0999	0999	0999	40
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TABLE 1. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL LOW BTU COAL GASIFICATION

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CONTROLLED

FUEL	REGION
COAL	NATIONAL AVERAGE

ROW	MNE-MON.	ACTIVITY PROCESS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX. COL 12)												AIR PO		
					DISSOLVED SOLIDS												
			ACIDS	BASES	PO_4	NO_3	OTHER	TOTAL (DS)	SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	SO_x
1		NATIONAL AVERAGE															
2	GASLO	LOW BTU GASIFICATION															
3	ATCCO	ATC COMBUSTOR	0.00+00 3 8005	0.00+00 3 8005	0.00+00 3 8005	0.00+00 3 8005	2.43 02 4 8005	2.43 02 4 8005	0.00+00 3 8005	0.00+00 1 8005	2.43 02 4	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	6.43+01 3 8104	3.04+00 3 8104	1.17+02 3 81
4	BOMAT	BOM ATMOSPHERIC	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	2.41+01 3 81
5	BOMPR	BOM PRESSURIZED	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	2.59+01 3 81
6	LURG	LURGI	0.00+00 3 8101	0.00+00 3 8101	0.00+00 1 8101	0.00+00 3 8101	0.00+00 3 8101	0.00+00 3 8101	0.00+00 3 8101	0.00+00 3 8101	0.00+00 3	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	3.32+00 3 807
7	KOPTK	KOPPERS-TOTZEK	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3 8090	0.00+00 3	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	5.20+00 3 8104	4.37+00 3 8104	2.23+01 3 81
8	ELCEN	ELECTRICITY GENERATION															
9	ATCBL	ATC BOILER	0.00+00 3 1917	0.00+00 3 1917	0999	0999	3.40+00 4 1917	3.40+00 4	0.00+00 3 1917	3.02-03 3 1917	3.40+00 4	0999	0999	0.00+00 3 1918	3.66+01 3 8105	1.82+00 3 8105	9.26+00 3 81
10	BOMAB	BOM ATMOSPHERIC BOILER	0.00+00 3 1917	0.00+00 3 1917	0999	0999	3.40+00 4 1917	3.40+00 4	0.00+00 3 1917	3.02-03 3 1917	3.40+00 4	0999	0999	0.00+00 3 1918	1.52+02 3 8105	2.38+01 3 8105	2.58+02 3 81
11	BOMPC	BOM-PRES. COMB. CYC	0.00+00 3 1917	0.00+00 3 1917	0999	0999	3.40+00 4 1917	3.40+00 4	0.00+00 3 1917	3.02-03 3 1917	3.40+00 4	0999	0999	0.00+00 3 1918	1.58+02 3 8105	2.73+01 3 8105	3.05+02 3 81
12	LURCC	LURGI-COMB. CYC	0.00+00 3 1917	0.00+00 3 1917	0999	0999	3.40+00 4 1917	3.40+00 4	0.00+00 3 1917	3.02-03 3 1917	3.40+00 4	0999	0999	0.00+00 3 1918	1.43+01 3 8031	1.09+01 3 8031	2.86+01 3 803
13	KOPTK	KOPPERS-TOTZEK-COMB. CYC	0.00+00 3 1917	0.00+00 3 1917	0999	0999	3.40+00 4 1917	3.40+00 4	0.00+00 3 1917	3.02-03 3 1917	3.40+00 4	0999	0999	0.00+00 3 1918	4.74 01 3 8105	1.97+01 3 8105	7.91+02 3 81
14	TRANS	TRANSMISSION	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 09
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12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
ERMAL $/10^{12}$BTU	PARTIC-ULATES	NO_x	SO_x	HYDRO-CARBONS	CO	ALDEHYDES ETC.	TOTAL	SOLIDS TONS / 10^{12}BTU	LAND $\left(\frac{\text{ACRE-YR}}{10^{12}\text{ BTU}}\right)$	DEATHS / 10^{12} BTU	INJURIES / 10^{12} BTU	MAN-DAYS LOST/10^{12}BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY (BTU/10^{12}BTU)	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
																			2
3 0997	8.43+01 3 8104	3.34+00 3 8104	1.17+02 3 8104	5.91+00 3 8104	3.30+00 3 8104	0.00+00 3 0997	1.94+02	6.63-02 3 8107	6.78+02 3 8106	0999	0999	0999	0999	7.78-01 2 8109	3.67+09 3 8108	4.66+04 3 8110	0999	0999	3
3 0997	0.00+00 3 0997	0.00+00 3 0997	2.41+01 3 8104	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	2.41+01	5.19+03 3 8107	7.81+01 3 8106	0999	0999	0999	0999	7.67-01 2 8109	3.43+10 3 8108	3.75+04 3 8110	6.13+04 3 8110	9.88+04 3	4
3 0997	0.00+00 3 0997	0.00+00 3 0997	2.59+01 3 8104	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	2.59+01	5.19+03 3 8107	7.22+01 3 8106	0999	0999	0999	0999	7.32-01 2 8109	3.47+10 3 8108	8.97+04 3 8110	1.44+05 3 8110	2.34+05 3	5
3 0997	0.00+00 3 0997	0.00+00 3 0997	1.32+00 3 8075	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.32+00	1.46+01 3 8058	1.66+00 3 8059	0999	0999	0999	0999	7.58-01 2 8060	5.27+09 3 8061	5.02+04 3 8096	1.44+05 3 8099	1.94+05 3	6
3 0997	5.20+00 3 8104	4.37+00 3 8104	2.23+01 3 8104	4.81+00 3 8104	3.24+00 3 8104	0.00+00 3 0997	3.99+01	5.77+03 3 8107	5.40+00 3 8106	0999	0999	0999	0999	7.92-01 2 8109	4.74+09 3 8108	1.32+05 3 8110	0999	0999	7
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3 1918	3.66+01 3 8105	1.82+00 3 8105	9.26+00 3 8105	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	4.77+01	0.00+00 3 0997	4.67+01 3 8106	1.55-04 3 3903	1.88-02 3 3903	2.08+00 3 3903	0999	3.80-01 2 1219	3.37+09 3 8109	1.41+05 2 8112	6.79+04 2 2907	2.09+05 2	9
3 1918	1.52+02 3 8105	2.38+01 3 8105	2.58+02 3 8105	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.45+02	0.00+00 3 0997	4.67+01 3 8106	1.55-04 3 3903	1.88-02 3 3903	2.08+00 3 3903	0999	3.80-01 2 1219	3.37+09 3 8109	1.41+05 2 8112	6.79+04 2 2907	2.09+05 2	10
3 1918	1.58+02 3 8105	2.73+01 3 8105	3.05+02 3 8105	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.63+02	0.00+00 3 0997	2.01+01 3 8106	1.55-04 3 3903	1.88-02 3 3903	2.08+00 3 3903	0999	4.00-01 2 8066	4.74+09 3 8109	1.53+05 3 8110	0999	0999	11
3 1918	1.83+01 3 8031	1.00+01 3 8031	2.86+01 3 8031	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.76+01	0.00+00 3 0997	4.18+01 3 8033	1.55-04 3 3903	1.88-02 3 3903	2. 8+00 3 3903	0999	4.00-01 2 8066	4.74+09 3 8062	1.53+05 3 8091	0999	0999	12
3 1918	4.74+01 3 8105	1.97+01 3 8105	1.91+02 3 8105	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	7.94+01	0.00+00 3 0997	4.61+01 3 8106	1.55-04 3 3903	1.88-02 3 3903	2.08+00 3 3903	0999	4.00-01 2 8066	4.74+09 3 8109	1.53+05 3 8110	0999	0999	13
3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	2.98+02 3 8037	0999	0999	0999	0999	9.12-01 2 1913	0998	0999	0999	0999	14
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TABLE 1. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL LOW BTU COAL GASIFICATION

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Footnotes for Table 1

1906 Source - (1906,46). 0.166 men per MWE is the basis for calculation. Injury data are from (1907,35). Half the combined deaths and permanent injuries are assumed to be fatal injuries. Permanent total disabilities are considered to represent 6000 days lost while other disabilities are estimated as 100 days lost.

1912 A large new powerplant is assumed to have a heat rate of 8960 Btu/KWH, equivalent to 38 percent conversion efficiency. The best plants have achieved around 8530-8900, whereas the National Average is around 10,500 (1913,I-5-6/I-5-7).

1913 Power sold divided by power produced, 1969 (1919,11,13).

1917 The basis for water pollutant calculations is the proposed effluent limitations guidelines and new source performance standards for the steam electric power generating point source category given in (1921). For new plants, best available demonstrated control technology (BADCT) requires effluent pH control in the range of 6-9. Hence acids and bases discharge will be negligible. BADCT also specifies total suspended solids levels no greater than 15 mg/l for all intermediate and low volume waste effluents. At this level of control there will generally be no net increase in suspended solids in water passing through the power plant system. Organics (oil and grease) must be controlled to 10 mg/l to meet BADCT standards. Hence, from (1921,232) these emissions will amount to 3.02-03 ton/10^{12} Btu. Information on the increase in total dissolved solids of water used in power plants is not readily available and was synthesized from (1922,10,12,20,22). Based on this data the net increase in total dissolved solids for water used by the power plant is 3.40 ton/10^{12} Btu.

1918 Thermal discharges are assumed to be completely eliminated by use of mechanical draft cooling towers.

2907 Capital and operating costs for controls are estimated as follows:

Control System	Capital Cost- $/Kw	Ref	Operating Cost- Mills/Kw-hr	Ref
Water Poll-Chemical	1	(1921,233)	.05	(1921,234)
Water Poll-Thermal	10	(1915)	.05	(1920,III-3)
Total	11		.10	

Based on the above, a 60P load factor and a net plant heat rate of 9053 Btu/Kw-hr (37.7P primary efficiency from footnote 2908) the incremental capital cost is 2.31+04 $/1.0E12 Btu and the incremental operating cost is 1.10+04 $/1.0E12 Btu. These are in addition to the costs given in footnotes

2906 and 3905. Note that incremental fuel costs associated with purchasing a .6P sulfur residual oil (for oil fired power plants) are not included in the above analysis. Although properly attributed to air pollution control costs, the cost of fuel is not considered in the operating and maintenance costs of the uncontrolled case and hence an incremental fuel cost is not given for the controlled case.

3903 See footnote 1906, using 0.089 men per MWE.

3905 Cost of gas fired power plant at $100/Kw,(1914) and (1915). Operating and maintenace cost exclusive of fuel cost at 0.51 mills/Kw-hr (1906,45). A 60P load factor is assumed and the FCR for capital is 10P.

8000 Primary efficiency for the ATC two-stage coal combustion process includes the decrease in efficiency associated with the necessity of thermal drying of the ROM coal from 22.25 to 4 percent moisture (8022-23). From (8006,13-3/13-25) and the fact that it takes 5.42E+04 ton of 9226.0 Btu/lb average Northwestern coal for 1.00E+12 Btu input, 1.10E+03 ton or 2.0 percent of the coal is consumed in drying. This leaves 4.34E+04 ton of 11285.6 Btu/lb coal going into the process. This 4.34E+04 tons of 4.0 percent moisture coal is then dried to 1.0 percent moisture prior to entering the combustor, leaving 4.21E+04 ton of 11715.6 Btu/lb coal (8022-23). Based on the above input to the combustor and that 3.79E+00 lb low Btu gas, at 2.58E+03 Btu/lb are produced per lb of Northwestern coal, the efficiency of gas production = 84.0 percent. The primary efficiency of the ATC combustor coal conversion process = 0.98 x 0.83 x 100.0 = 81.0 percent.

8001 The land impact of the ATC coal combustion process consists of equipment for thermal drying (see footnote 8000), equipment for the combustor unit and desulfurization unit, limestone storage and desulfurization slag storage. Coal storage will be allocated to the utility since the combustor can be retrofitted to an existing facility (8015,45). No impact on land area could be found for thermal drying. It will be assumed at 0.10 acre. The impact of equipment for the combustor and desulfurization unit will be 4.50 acres, assuming a 1000 MW utility employing four 28 ft diameter combustors, sulfur recovery system, coal, limestone and air preparation equipment (8025). From (8029), the use of the Northwestern coal will require 0.0119 lb limestone/lb coal feed to the process,and 0.0687 lb stored slag/lb coal feed is produced. For 4.34E+04 ton coal feed (see footnote 8000), 5.16E+02 ton of limestone is needed. For 4.21+04 ton of coal fed to combustor (see footnote 8000), 2.89+03 ton of stored slag is produced.

Assuming a pile height of 30.0 feet and a density of 0.083 T/CF for limestone and 0.060 T/CF for stored slag, 9.78E-03 acre/yr and 1.11E-01 acre/yr are used. Total land impact, acre yr/1.00E+12 Btu = 4.78E-02 + 1.60E-02 = 6.72E-02.

8002 Particulate emission sources are the coal fired thermal dryer, air blown dryer, limestone dryer - crusher and combustor. A fluidized bed thermal dryer with a 99.0 percent efficient venturi will emit 0.2 lb particulate/ton of coal feed (0002,8-10). With an input of 5.42E+04 ton coal/1.00E+12 Btu, particulate = 5.42E+01 ton. The air blown dryer will have the same emissions as the coal fired dryer. For the 4.34E+04 ton of coal fed into the system (see footnote 8000), 4.34E+01 tons of particulate are produced. Crushing of limestone with a 99.0 percent efficient bag house will produce 8.52E-02 tons of particulate (0002,8-15). Drying of limestone is similar to drying of gypsum, thus with the use of a fabric filter 0.2 lb/ton of particulate is emitted or 5.16E-02 ton. (0002,8-14) The only particulates from a commercial size combustor will be metallics, from bubbles bursting in the iron bath (8022,105/107). This amounts to 1.82E-04 lb/SCF in the test combustor but will be reduced at least by 99.0 percent or 1.82E-05 lb/SCF in the commercial (due to 4 times flue). 1.0 lb coal will produce 5.83E+01 SCF of gas (8029), for 4.21E+04 ton of coal input to the system 4.96E+09 SCF gas is produced yielding 4.52E+01 ton of particulate. This particulate will not emerge from the conversion process but will be emitted from the utility and will be allocated to it. Total particulate emission from the conversion process = 5.42E+01 + 4.34E+01 + 8.52E-02 + 5.16E-02 = 9.77E+01 ton.

8003 Sources of air emissions for ATC-combustor process will be from the primary coal fired fluidized bed thermal dryer and Claus plant. Pollutants inherent in the combustor fuel gas are allocated to the utility where they occur. A well controlled thermal dryer will emit 0.54 lb NO_x/1.00E+06 Btu, 0.045 lb SO_x/1.00E+06 Btu, 0.58 lb hydrocarbon/1.00E+06 Btu and 0.39 lb CO/1.00E+06 Btu. From the coal used in firing (1121), 1.10E+03 ton of 9226.0 Btu coal or 2.03E+10 Btu is used for firing, thus 5.48E+00 ton NO_x, 4.57E-01 ton SO_x, 5.89E+00 ton hydrocarbon and 3.96E+00 ton CO is produced. Emission from the Claus plant consists of SO_x. From the molar composition of $H_2S + SO_2$ of 35.0 percent of the gas and (8012) the Claus plant efficiency is 92.0 percent from (8029), H_2S = 3.20E-03 lb/ lb coal and SO_2 = 2.80E-03 lb SO_2/lb coal. Total S available = 4.41E-03 lb/lb coal. For 4.21E+04 tons coal, 1.49E+01 ton of S is available as an emission or as SO_2 = 2.97E+01 ton. Total SO_2 = 4.57E-01 + 2.97E+01 = 3.00E+01 ton.

8004 Ancillary energy demand is stated as 12 MW for 1000 MW of electricity produced to operate the equipment necessary for the conversion process (8025). 1.00E+12 Btu input will produce 9.31E+04 MW, (8029) thus ancillary energy = 1.12E+03 MW or 3.83E+09 Btu (8029).

8005 Water effluent from the conversion process occurs only from runoff from stored slag. The conversion process is a closed loop with respect to water use. From (8022, 147), the sulfate runoff, given a slag of 1.0 percent sulfur, is 23.0 PPM sulfate or 2.85E-01 GM/SQFT or 2.43E-02 ton.

8006 Solid waste consists of desulfurized slag only. Sulfur will be sold at current market prices. In the Northwest, slag will not have a market (8025), it is considered a solid waste. Solid waste = 2.89E+03 ton (see footnote 8001).

8007 Air emissions from the utility utilizing the ATC process depends upon the composition of the gas. One pound of Northwestern coal will produce a gas composition as follows (8029):

CO	1.4232 lb
H_2	0.0577 lb
CO_2	0.0001 lb
N_2	2.3049 lb

The gas will also contain 22.0 PPM SO_x (8015,29), 22.5 PPM NO_x (8025) and 5.42E+01 ton particulate (footnote 8002).

For combustion of the low Btu gas, a firing temperature of 1100F - 1200F will be used (8025). Assuming combustion is essentially complete, the emission from fuel gas combustion, given 4.21+04 ton of coal input or 3.12+08 ton of gas (footnote 8002), = 3.11E+00 ton SO_x and 3.23E+00 ton NO_x and 2.26E+02 ton particulate. Total emission through the stacks are as follows:

Particulates	SO_x	NO_x
5.42E+01	3.11E+00	3.23E+00

8009 SO_2 emissions from the BOM Atmospheric Gasification Activity is 3.95E+01 tons. Figure is based on a coal input of 3.62E+04 tons/yr. Of the 0.68 moles of H_2S fed to the absorber, 80 percent is reacted and 97 percent is regenerated. Emission of H_2S is considered as SO_2 (8010).

8010 Air emissions for the BOM-Atmospheric Conversion Process, using the Northern Appalachian coal, consist only of SO_x vented from the ammonia sulfate plant (8030). 80.0 percent of the H_2S in the initial combustor fuel gas is removed by the iron oxide absorber. Upon regeneration, a gas rich in SO_2 is formed. This is then fed to an ammonia sulfate plant which has an efficiency of 97.0 percent (8030). The Northern Appalachian coal will produce a feed of 69.70 lb SO_2 equivalent/ton of coal (8030), therefore the emission is 2.18 lb SO_x/ton of coal. For a 1.00E+12 Btu equivalent of 3.94E04 ton of coal, 3.95E01 ton of SO_x is produced.

8011 Air emissions for the BOM conversion process occurs from ammonia sulfate production as described in footnote 8009. For Central and Northwest coals, with feeds of 3.82E01 lb and 1.48+01 lb SO_2 equivalent/ton of coal to the ammonia plant and coal feeds of 3.62E04 tons of coal and 5.42+04 ton of coal respectively, 2.07E01 ton and 1.20+01 ton of SO_x are emitted respectively.

FTN. 8012-8016

8012 The BOM-Atmospheric Gasifier will require 5.42+04 tons of 9226 Btu Northwestern coal per 1.00E12 Btu input. 6.38 percent of this is ash. Assuming essentially all of this can be removed from the combustor, solid waste = 5.42E04 x 0.0638 = 3.46E03 ton (8030). This solid waste will be returned to the mine as fill.

8013 The BOM-Atmospheric Gasifier will require 3.62E04 tons of 13800 Btu/lb Northern Appalachian coal per 1.00E12 Btu input. 14.0 percent is ash and assuming all can be removed from the combustor,solid waste = 0.14 x 3.62E04 = 5.06E03 ton (8030). 50 percent will be returned as fill to the mine.

8014 The BOM-Atmospheric Gasifier will require 4.15E04 tons of 12050 Btu/lb Central regional coal per 1.00+12 Btu input. 17.3 percent is ash. Assuming all ash is removed from the combustor,solid waste= 0.173 x 4.15E04 = 7.06E03 ton (8030).

8015 The land impact for the BOM-Atmospheric Combustor process using Northern Appalachian coal consists of the equipment for conversion and sulfur removal and for ash storage. The conversion and sulfur removal systems have a fixed impact of 50.4 acres. From footnote 8013,2.53E03 ton of ash will be produced. In a pile 30.0 ft high, ash will occupy 2.91E-01 acres. Fixed land impact for processing 1.00E+12 Btu/yr is 4.76E-01 Acre-yr. Time averaged land impact for ash disposal is 3.43E-01 acre-yr. Total land impact is 8.196-01 acre-yr/1.00E+12 Btu (8031).

8016 The land impact for the atmospheric combustor using a Central regional coal having a heating value of 12050 Btu/lb consists of land required for the ash storage pile, gasifier, gas treating facility, and the sulfur plant. The ash storage pile assuming a 50 foot pile occupies 4.85-01 acres/1.00E12 Btu. For a throughput equivalent to operate a 1000MW plant the land impact is 3.76 acres. This is time averaged over 25 years. The fixed land impact is 2.26 acres, The time averaged land impact per Btu throughput is 1.07E00 acres (8031).

8017 For the BOM-Pressurized Combustor using a Central region coal the only air emissions occur in the ammonia sulfate plant. For a 1000 lb feed 1.154 lb of SO_2 is released (8030). For a 1.00E12 Btu feed of 4.15E04 ton of coal, the SO_2 emission is 2.40E01 ton.

8018 For the BOM-Pressurized Combustor using a Northern Appalachian coal, the only air emissions occur from the sulfur recovery process in the ammonia sulfate plant. For a feed of 1000 lb of coal, 1.09+00 lb of SO_2 equivalent is released (8030). For an input of 1.00+12 Btu of 13800 Btu/lb coal, the SO_2 emission = 3.95E01 tons.

8019 Land impact associated with the BOM-Pressurized Combustor consists of the gasifier, gas treatment plant, sulfur plant, and cooling, and ash storage system. For a Central regional coal this equals 2.50E-02 acres/1.00E+12 Btu input and a time-averaged ash storage of 4.94E-01 acres over 25 years assuming 50 foot pile. Total land impact = 9.98-01 acres (8031).

8020 Land impact for the BOM-Pressurized Combustor utilizing a Northern Appalachian coal is identical to fixed land impact for footnote 8019, however it is adjusted to reflect change in Btu content of gas produced. Fixed land impact = 2.40E-02 ash is the same. Total land impact = 2.40E-02 + 4.94E-01 = 7.51E-01 acres (8031).

8021 Air emissions for the BOM-Pressurized combined cycle boiler consist of SO_2. For an input of 1.00E+12 Btu of gas 1.48E+04 moles of SO_2 are formed (8036). SO_2 = 4.74E+01 tons/1.00E+12 Btu.

8022 Product gas from the absorber contains 0.136 moles of H_2S/8.96E06 Btu (8030). For a boiler feed of 1.00+12 Btu, gas contains 1.54E04 moles of H_2S. Assuming complete combustion 4.88E02 tons of SO_2/1.00E12 Btu are formed.

8023 Product gas from the absorber contains 0.075 moles of H_2S/8.97E06 Btu of gas. For 1.00E12 Btu of gas produced and fed to boiler 8.40E03 moles of H_2S are converted to SO_2 assuming complete combustion. SO_2 = 2.69E02 tons/ 1.00E12 Btu.

8024 Product gas from the spray cooler contains 0.075 moles H_2S/8.72E06 Btu of gas. For 1.00E12 Btu of gas produced and fed to boiler 8.63E03 moles of H_2S are converted to SO_2 in boiler.Assuming complete combustion (8030), SO_2 = 2.78E02 tons/1.00E12 Btu.

8025 Particulate emissions consist of carbon and sulfur dust emitted from the boiler. For a 1000 lb Central region coal feed, 3.02E01 lbs of dust are emitted.For a coal feed of 4.15+04 ton/1.00E12 Btu,emission is 1250 tons dust (8030). Dust or particulates are removed by 80 percent in absorber hence particulates = 1.25 ton/ 1.00E12 Btu. For use in a combined cycle power plant an additional 97 percent particulate removal must be obtained by electrostatic precipitator (0002-A5).

8026 Particulate emissions for the boiler consist of dust as in footnote 8025. For a 1000 lb feed emissions are 3.19E01 tons. For 1.00E12 Btu feed of 3.62+04 tons and 90 percent removal in absorber and 97 percent by precipitator particulate emissions= 3.44 ton/1.00E12 Btu (8030,0002-A5).

8027 Particulate emissions consist of carbon and sulfur. emitted from boiler. For a 1000 lb feed, 3.02 lbs are emitted in gas and 90 percent is removed in absorber (8030). For 4.15E04 ton/1.00E12 Btu feed particulates = 1.25E02 tons/1.00E12 Btu.An electrostatic precipitator at 97 percent efficiency yields 3.75E+00 tons.

8028 For 1000 lb coal feed particulates = 3.19 lb for 90 percent removal and coal feed of 3.62E02 ton/1.00E12 Btu.Emission = 1.15E02 ton/1.00E12 Btu (8030). See footnote 8027.

8029 For 1.00 lb of coal fed to producer, 0.001 lb H_2S/6.04E03 Btu of gas is formed. For boiler feed of 1.00E12 Btu and assuming complete combustion SO_2 = 1.56E02 tons SO_2/ 1.00E12 Btu (8030).

8030 Particulate emission from the absorber is 0.0026 lb/ 6.04E03 Btu of gas produced. For a feed of 1.00E12 Btu of gas, 2.16E02 tons of particulates are generated (8030).

8031 Air emissions from the Lurgi Combined Cycle Process consist of SO_x, NO_x, and particulates. Emissions are: (8027)

NO_x = 0.021 lb/1.00E06 Btu input
SO_x = 0.057 lb/1.00E06 Btu input
Particulates = 0.029 lb/1.00E06 Btu input

For a 1.00E12 Btu input air emissions are:

NO_x = 1.00E01 ton/1.00E12 Btu
SO_x = 2.86E01 ton/1.00E12 Btu
Particulates = 1.43E01 ton/1.00E12 Btu

8032 Land impact for the BOM-Atmospheric Combustor consists of fixed land impact of 50.4 acres for equipment necessary for conversion of 1.00E12 Btu/yr·The time-averaged land impact = 4.20E-01 acres (8031).

8033 The land impacts for the power generation cycle consist of fixed land impacts only. From footnote 3902 land impact for a 3000 MW plant = 150 acres. For a 1000 MW plant this equals 50 acres. Annual Btu throughput to operate a 1000 MW plant is as follows:

Northern Appalachian Coal = 1.06E14 Btu/yr
Central Regional Coal = 1.00E14 Btu/yr
Northwest Coal = 1.20E14 Btu/yr

For a fixed land impact of 50 acres this yields an impact of: 0.482 acres/1.00E12 Btu, 0.500 acres/1.00E12 Btu, and 0.418 acres/1.00E12 Btu respectively (8030).

8034 Particulate emission from spray cooler yields 0.211 lbs/6.83E03 Btu. For 1.00E12 Btu of product fed to boiler 1.56E04 tons particulates are produced. Using an electrostatic precipitator of 97 percent efficiency this yields 4.68E02 tons particulates (8030).

8035 Land impacts for the BOM-Atmospheric combined cycle generating system is 1.26 acres/58.2 MW plant (8031). For a 1000 MW plant it equals 21.7 acres. To run a 1000 MW power plant the following gas heating composition must be fed to the turbines/yr:

FTN. 8036-8041

N. Appalachian Coal	1.06E14 Btu/yr
Central Regional Coal	1.00E14 Btu/yr
Northwest Coal	1.20E14 Btu/yr

For a 1.00E12 Btu input the land impact would be as follows:

N. Appalachia = 2.05E-01 acres/1.00E12 Btu
Central Regional = 2.17E-01 acres/1.00E12 Btu
Northwest = 1.81E-01 acres/1.00E12 Btu

8036 Based on calculations in (8030) SO_2 emissions from the ammonia sulfate plant are 0.00026 lb/lb coal input. For a 1.00E12 Btu coal input of 5.42E04 tons, SO_2 emissions are 1.41E01 tons/1.00E12 Btu (8030).

8037 Power transmission is based on 3200 MW capacity line with a load factor of 0.70 (8033,I-13). Capacity is 6.70E+13 Btu/yr. From (8033,I-1)right of way is 20.0 acres/mile and transmission distance is assumed at 1000 miles. For 1.00E+12 Btu input the land impact is 2.98E+02 acres. Transmission distance based on distance from Four Corners to Chicago.

8038 Power transmission is based on 3200 MW capacity line with a load factor of 0.70 (8033, I-13). Capacity is 6.70E+13 Btu/yr. From (8033,I-1) right of way is 20.0 acres/ mile and transmission distance is 450 miles. For 1.00E12 Btu input the land impact is 1.35E+02 acres. Transmission distance based on distance from Pittsburgh to Chicago.

8039 Ancillary energy for a 150 ton/hr plant requires 34,745 KWH/H. For a 1.00E12 Btu coal feed of 12,100 Btu/lb coal, this is equivalent to 3.27E+10 Btu. (8010,19).

8040 Ancillary energy for a 150 ton/hr plant required 34,745 KWH/H. (8010,19). For a 1.00 E12 Btu coal feed of 9226 Btu/lb coal, this is equivalent to 4.28E+10 Btu.

8041 Ancillary energy for a 150 ton/hr plant requires 34,745 KWH/H (8010,19). For a 1.00E+12 Btu input of 13,800 Btu/lb coal, this is equivalent to 2.86E+10 Btu.

8042 Ancillary energy for a 150 ton/hr plant is 34,415 KWH/H (8010,19). For a 1.00E+12 Btu input of 12,100 Btu/lb coal, this is equivalent to 3.23E+10 Btu.

8043 Ancillary energy for a 150 ton/hr plant is 34,415 KWH/H (8010,19). For a 1.00E+12 Btu input of 13,800 Btu/lb coal, this is equivalent to 2.83E+10 Btu.

8044 Ancillary energy for a 150 ton/hr plant is 34,415 KWH/H (8010,19). For a 1.00E+12 Btu input of 9226 Btu/lb coal, this is equivalent to 4.22E+10 Btu.

8045 Land impact for an ATC Combustion process consists of land for thermal drying, combustors, desulfurization unit, limestone and slag storage. Coal storage will be allocated to utility since combustor can be retrofitted (8015,45). Thermal drying is assumed to require 0.10 acres. 4.50 acres are required for combustor and desulfurization units (8025).The use of 11,503 Btu/lb coal requires 0.224 lb limestone/lb coal and produces 0.1101 lb slag/lb of coal of which 50 percent is sold. For a feed of 4.90E+04 tons coal this produces 1.10E+03 tons/yr limestone and 2.69E+03 tons of slag. Assuming limestone and slag have a density of 0.083 t/cf and 0.060 t/cf respectively, a refuse pile 30 feet in height would occupy 1.34E-01 acres/yr. Time averaged over 25 years would equal 2.94E-02 acre-years/1.00E+12 Btu. Fixed land impact is 4.60 acres. On 1.00E+12 Btu basis = 5.33E-02. Total land impact is 8.27E-02 acres-yr/1.00E+12 Btu for yearly output of 8.67E+13 Btu/yr.

8046 Land impact for an ATC Combustion process utilizing Northern Appalachian coal at 12696 Btu/lb requires 4.50 acres for combustors and desulfurization equipment. Coal storage is applied to utility. Limestone and slag produced is 0.0262 lb coal input and 0.0899 lb coal input respectively (8029). 50 percent of the slag is sold. For a coal feed of 3.94E+04 ton/1.00E+12 Btu, 1.03E+03 ton of limestone and 3.54E+03 tons of slag is produced. Assuming 30 ft high refuse pile and a density of limestone of 0.083 ton/cf and slag of 0.060 t/cf this occupies an area of 1.06E+14 Btu/yr this equals 1.45E-02 acre-yr/1.00E+12 Btu. Fixed land impact for output of 1.06E+14 Btu/yr equals 4.24E-02 acre-yr/ 1.00E+12 Btu. Total = 5.69E-02 acres-yr/1.00E+12 Btu.

8047 The efficiency of the ATC-Combustor Conversion process utilizing a Pittsburgh coal having 12696.0 Btu/lb, 1.0 percent moisture and 13.85 percent ash, will be Btu gas out/Btu coal in. From (8029) 1.0 lb of coal will yield a gas of 9.34E+03 Btu. For a 1.00E+12 Btu input, 3.94E+04 ton of coal is input producing 7.36E+11 Btu of gas. Thus efficiency = 7.36E+11/1.00E+12 = 0.736

8048 The efficiency of the ATC-Combustor Conversion process includes the decrease in efficiency associated with the necessity of thermal drying of the 10050.0 Btu, 15.31 percent moisture ROM Illinois No. 6 coal to a 4.0 percent moisture coal (8022,23). From (8006,13-3/13-25) and the fact that it takes 4.97E+04 ton/1.00E+12 Btu input, 6.70 E+02 ton or 1.3 percent of the coal is consumed in drying. This leaves 4.35E+04 ton of 11332.0 Btu coal going into the process. Then it is air dried to 1.0 percent moisture prior to entering the combustor, or 4.22E+04 ton of 11503 Btu coal. Based upon this input to the combustor and that 9.19E+03 Btu of gas is produced/lb coal, efficiency= 0.799 x 0.986 = 0.788.

8049 Sources of air emissions for the ATC-Combustor process utilizing Central coal will be from the coal fired thermal dryer and Claus plant. Pollutants inherent in the combustor fuel gas are allocated to the utility where they occur. A well controlled thermal dryer will emit 0.54 lb NO_x/1.00E+06 Btu, 0.045 lb SO_x/1.00E+06 Btu, 0.58 lb hydrocarbon/1.00E+06 Btu and 0.39 lb CO/ 1.00E+06 Btu.From the coal used in firing(1121), 6.70E+02 ton of coal will be consumed in drying (see footnote 8048) or 1.35E+10 Btu.Thus 3.64E+00 ton NO_x, 3.00E-01 ton SO_x, 3.92E+00 ton hydrocarbon and 2.63E+02 ton CO will be emitted.From the Claus plant the only emission is SO_x. From molar H_2S + SO_2 percent of 31.0 percent of the input gas and (8012), the Claus plant efficiency is 92.0 percent. From (8029), H_2S = 2.67E-02 lb/lb coal and SO_2 = 2.50E-02 lb/lb coal is input of Claus. The output equals 0.0060 lb/lb coal on an SO_2 basis. For an input of 4.75+04 ton of coal, SO_x = 2.86E+02. Total SO_x = 2.86E+02 + 3.04E-07 = 2.86E+02 SO_x.

8050 Air emissions, other then particulate, for the ATC-Combustor, utilizing No. Appal. coal, occur from the Claus plant. The emission is SO_x. From molar H_2S + SO_2 percent of 32.0 percent of the input gas and (8012), the Claus plant efficiency is 92.0 percent. From (8029), H_2S = 3.97E-03 lb/lb coal and SO_2 = 3.50E-03 lb/lb coal is input to Claus, giving an output of 0.0009 lb SO_2 equivalent/lb coal. For an input of 3.94E04 ton of coal/1.00E12 Btu into the conversion process, SO_x = 3.94E+04 x 0.0009 = 3.55E+01 ton.

8051 Particulate emission sources using Central coal consist of the coal fired thermal dryer, air blown dryer, limestone dryer-crusher and combustor. A fluidized bed thermal dryer with a 99.0 percent efficient venturi scrubber will emit 2.0 lb particulate/ton coal feed (0002,8-10). With an input of 4.97E+04 ton of ROM coal/1.00E+12 Btu, particulate = 4.97E+01 ton, for the air blown dryer, for 4.35E+04 ton of coal fed into the system (see footnote 8048), particulates = 4.35E+01 tons. Crushing and drying of limestone with a 99 percent efficient bag house and a throughput of 1.00E+03 ton of limestone will emit 7.18E+00 ton and 4.35E+00 ton respectively (8002,8-14/8-15). The only particulates from the combustor are metallics (8022,105/107). This amounts to 1.82E-04 lb/SCF in the test combustor, but will be reduced by at least 99 percent in the commercial size combustor or 1.82E-05 lb/SCF of gas (8029). Particulates = 7.15E+01 x 1.82E-05 = 1.30E-03 lb/lb coal or for 4.22E+04 ton input to the combustor particulate = 5.49E+01 ton. The particulate will be emitted at the utility and not considered part of the conversion process. Therefore total particulate from conversion = 4.97E+01 + 4.35E+01 + 7.18E+00 + 4.35E+00 = 9.47E+01 ton.

8052 SO_2 emissions from the BOM combined cycle plant consist of the H_2S contained in the gas from the spray coolers. This gas contains 0.0012 lb H_2S/6.83E+03 Btu output. For a feed to the boiler of 1.00E+12 Btu, 1.76E+05 lbs or 5.16E+03 moles H_2S are formed. Assuming complete combustion, 1.65E+02 tons SO_2/1.00E+12 Btu are formed (8016).

8053 Sources of air emission from the Koppers-Totzek Conversion process, using Central regional coal, are the coal fired thermal dryer and the Claus plant. Another potential source of emission is from the coal pulverizing operation, but all dust is captured and sent to the gasifier (8023). From (8006,13-3/13-25) and the fact that it takes 4.97E+04 ton of 10050.0 Btu Central coal/1.00E+12 Btu input, 7.06E+02 ton of coal is consumed. The emissions are 0.2 lb particulate/ton coal feed (99.0 percent efficient venturi scrubbing) (0002, 8-10), 0.54 lb NO_x/1.00E+06 Btu fired (8035), 0.045 lb SO_x/1.00E+06 Btu fired (8035), 0.58 lb hydrocarbon/ 1.00E+06 Btu fired (8035) and 0.39 lb CO/1.00E+06 Btu fired for thermal drying. From the above, emission for the thermal drying = 4.97E+00 ton particulate,2.70E+02 ton NO_x.For every lb of coal combusted in the combustor, 0.052 lb of H_2S and 0.006 lb of COS is formed. On a 1.00E+12 Btu basis, this yields a total of 4572 tons H_2S and COS on SO_2 basis (8034,14). 90.0 percent of this SO_2 is removed in the Rectisol unit and directed to the Claus plant. Of the 4115 tons input to the Claus plant with Stretford tail gas cleanup, 99.0 percent is removed. SO_2 = 41.2 tons/1.00E+12 Btu. Total SO_x = 4.12E+01 + 3.20E-01 = 4.12E+01 ton SO_x.

8054 SO_2 emissions for the Koppers-Totzek Electrical Generation process utilizing Central coal occurs in the boiler activity. Assuming complete combustion of the H_2S and COS entering the system 10 percent x 4572 = 457.2 tons of SO_2 is formed and emitted. See footnote 8053 (8034,14).

8055 The only sources of particulates for the ATC-Combustor process utilizing a Northern Appalachian coal are the limestone crusher-dryer and the combustor. Crushing and drying of limestone with a 99.0 percent efficient bag house and a throughput of 1.03E+03 ton of limestone will emit 2.06E-01 ton and 1.70E-01 ton respectively (0002,8-14/8-15). The combustor will emit metallics, which in the commercial size combustor equals 1.82E-05 lb/SCF gas. 1.0 lb coal will produce 80.89 SCF of gas (8029). Particulate = 80.89 x 1.82E-05 = 1.47E-03 lb/lb of coal or for 3.90E+04 ton coal input to the combustor, particulate = 57.4 lb. The metallic particulate will be emitted at the utility and not be considered part of the conversion process. Particulate from conversion = 3.76E-01. Particulate from utility = 5.74E-01 ton.

8056 SO_2 emissions from the Koppers-Totzek process utilizing Northern Appalachian coal, at 12,696 Btu/lb, occur in the Claus-Stretford plant only. For every lb of coal combusted 0.0110 lb of H_2S and 0.0022 lb of COS are formed. On a 1.00E+12 Btu basis this yields a total of 911.6 tons H_2S and COS on a SO_2 base (8034,14). 90 percent is removed in a Rectisol unit and directed to a Claus-Stretford plant for further gas treating, up to 99 percent efficient. SO_2 = .90 x 911.6 tons x 0.01 = 8.21 tons SO_2/1.00E+12 Btu.

8057 SO_2 emissions for Koppers-Totzek electric generation process occur in the combined cycle activity. Of the 10 percent total SO_2 equivalent emitted from the Rectisol unit, 100 percent is combusted in the boiler. Total SO_2 emitted equals 91.2 tons/1.00E+12 (8034,14). See footnote 8056.

8058 Solid waste as ash generated in the Lurgi Conversion process is 3.46E+03 ton based on a feed of 5.42E+04 ton of 6.38 percent ash Northwest coal. All other output will be sold (8031).

8059 Land impact for the Lurgi Conversion process consists of fixed facilities and evaporation pond since ash will be shipped back to the mine (see footnote 8058). For a Lurgi plant having an input of 3.03E+13 Btu/yr of 12,927 Btu/lb Northwest coal, land impact is 50.4 acres. For a 1.00E+12 Btu input land impact is 1.66E+00 acres (8012,II-A-I).

8060 The efficiency of the Lurgi fuel gas process is 75.8 percent based on an input of 3.03E+13 Btu/yr and an output of 2.30E+13 Btu/yr (8012,II-A-I).

8061 Ancillary energy demand for the Lurgi Conversion process consists of power requirements for fuel gas production, fuel gas cooling, and fuel gas treating. Total requirement for 3.03E+13 Btu/yr input (see footnote 8060) is 9400 KWH/H. For a 1.00E+12 Btu input total ancillary energy is 9.27E+09 Btu (8012, II-D-5).

8062 Ancillary energy demand consists of 2590 KWH/H for steam generation (8012,II-D-5) plus power required for air compression. From (8012,Area 23) 20.6 percent of total plant energy demand for air compression (5150 KWH/H) is associated with the electric generation process. Total ancillary energy is 3650 KWH/H. For an input of 2.30E+13 Btu/yr the power requirement is 1.09E+10 Btu/yr. For a 1.00E+12 Btu input, total ancillary energy is 4.74E+08 Btu.

8063 Land impact for the Kopper-Totzek Conversion process consists of land required for the combustors,clarifiers, sulfur removal plant, water cooling and coal drying.Ash is to be returned to the mine.For a 1000 MW plant 11 acres are required (8023).For a 1000 MW plant, a coal feed of 5.47E+07 tons/yr is required, considering a 74.4 percent conversion and 40.0 percent generation efficiency using a Northwest coal at 9226 Btu/lb. For a 1.00E+12 Btu input land impact is 1.00E+12 Btu x 11 acres/1.01E+14 Btu/yr input = 1.09E-01 acre-yr/ 1.00E+12 Btu (8023).

8064 Efficiency for the Koppers-Totzek Conversion process is 74.4 percent based on a coal input of 9226 Btu and gas output of 6863 Btu (8023).

8065 Efficiency of Koppers-Totzek Combined Cycle Power Generation Activity is 40.0 percent based on calculations from (8034,10). This assumes a 90 percent load factor and the system from (8034,10).

8066 From (8034,10) and assuming a 90 percent load factor, it takes 8500 Btu input to generate 1.00 KWH. Efficiency = 3413/8500 = 4.01E-01.

8067 Efficiency for the Koppers-Totzek Conversion process using Northern Appalachian coal is 82.0 percent for a coal input of 12,696 Btu and output of 10,407 Btu (8023).

8068 Solids generated during the Koppers-Totzek process using Northern Appalachian coal consist of 0.1372 lb ash/lb coal input (8023). For an input of 9.12E+13 Btu/ yr, 4.93E+05 tons of ash are produced. Solid waste is 5.41E+03 tons ash/1.00E+12 Btu input.

8069 Land impact for the Koppers-Totzek Conversion process for a 1000 MW plant is 10 acres. For a yearly input of 9.12E+13 Btu of coal and a conversion and generating efficiency of 82 percent and 40 percent respectively, on a 1.00E+12 Btu basis land impact is 1.10E-01 acre-years. Land required for ash storage is 3.86+00 acre for an input of 9.12E+13 Btu/yr of 12,696 Btu/lb coal. For an input of 1.00E+12 Btu time averaged 25 years, land impact is 3.98E+00 acre-years/1.00E+12 Btu (8023). This assumes a pile height of 30 feet, ash density of 0.02 tons/cf and that 0.1372 lb ash/lb coal is generated. See footnote 8068.

8070 Solid waste for the Kopper-Totzek Conversion process is 3.46E+04 ton/1.00E+12 Btu input based on an input of 1.01E+14 Btu/yr and a coal heating value of 9226 Btu/lb coal. Ash generation is 0.0638 lb/lb coal input (8023).

8071 Solid waste for BOM-Pressurized conversion process is 3.46E+03 ton based on an ash content of 6.38 percent and coal feed of 6.50E+06 ton/yr and an input of 1.20E+14 Btu/yr (8016). On a 1.00E+12 Btu basis this is 3.46E+03 tons.

8072 For an input of 1.20E+14 Btu to serve a 1000 MW plant 50.4 acres are required. For 1.00E+12 Btu input basis this is 4.17E-01 acres (8012). Solid waste will be returned to the mine,hence incremental land impact is zero.

8073 Solid waste for the ATC Conversion process is 0.00E+00 ton. All slag and iron can be sold (8029).

8075 The only air emission from the Lurgi Conversion process is from the sulfur recovery process (8031, III-12-2). 94.0 percent of the H_2S in the combustor gas is removed by the contacters of the Stretford process (8031, III-22-1). The absorber then removes 99.4 percent of the H_2S, the offgas from the absorber is flared. Based on a combustor gas of 0.0051 S/lb coal to the combustor and a feed of 5.42E+04 ton of coal to the combustor, sulfur released equals 1.66 tons/10^{12} Btu input, or 3.32 tons $SO_x/10^{12}$ Btu.

8076 Air emissions from generation of electricity utilizing the ATC process depends on the gas composition being fired. 1.0 lb of Northern Appalachia coal will produce a gas with the following composition (8029):

1.6533 lb CO
0.0505 lb H_2
0.8559 lb O_2
0.0128 lb CO_2
3.2045 lb N_2
44.00 PPM H_2S

Upon combustion in a boiler system fired at 1100F - 1200F and assuming nearly complete combustion, the only pollutants emitted are as follows - 22.5 ppm NO_x (8025) and 22.0 ppm SO_x (8015,29). For a 1.00E12 Btu input of gas (5.35E04 ton), the emissions are 1.11E00 ton NO_x and 1.08 ton SO_x.

8077 Land impact is 1.21 acres for the Kopper-Totzek conversion process using a Central coal. For an input of 9.23E+13 Btu and 11 acres, fixed land impact is 1.09E-01 acres. For a coal feed of 9.23E+13 Btu/yr ÷ 1.1338E+04 Btu/lb = 4.07E+06 ton/yr, 7.78E+05 tons of ash are produced. (8023). Based on a 30 foot pile and an ash density of 0.02 t/cf the ash, all of which is stored, will require 12.0 acre-yr/1.00E+12 Btu. Total land impact is 1.21E+01 acres.

8078 For an input of 9.23E+13 Btu/yr and 11,338 Btu/lb coal, 7.78E+05 tons ash/yr is produced based on an ash content of 19.1 percent (8023). For 1.00E+12 Btu equivalent feed, solid waste is 8.43E+03 tons.

8079 Efficiency for the BOM-Pressurized conversion system is 73. percent based on a coal input of 12,050 Btu/lb and a gas output of 8796 Btu/lb (8016).

8080 Efficiency of the BOM-Pressurized conversion process is 73.4 percent based on a coal input of 13,800 Btu/lb and a gas output of 10,133 Btu/lb (8016).

8081 Efficiency of the BOM-pressurized conversion process is 73.3 percent based on an input of 9226 Btu/lb and a gas output of 6765 Btu/lb (8016).

8082 Air emissions from generation of electricity utilizing the ATC process depends upon the gas composition being fired. 1.0 lb of 1.0 percent moisture Central coal will produce a gas with the following composition (8029):

1.4651	lb	CO
0.0451	lb	H_2
0.0012	lb	CO_2
2.8162	lb	N_2
0.7529	lb	O_2
44.00	PPM	H_2S

Upon combustion in a boiler system fired at 1100F-1200F and assuming nearly complete combustion, the emission will be as follows - 22.5 PPM NO_x (8025) and 22.0 PPM SO_x (8015,29). For a 1.00E12 Btu input of gas (5.44E04 ton), the emissions are 1.12E00 ton NO_x and 1.10 ton SO_x.

8083 Efficiency for the BOM-ATM conversion process is 78.3 percent based on a coal input of 12,050 Btu/lb and gas and tar output of 9441 Btu/lb (8016).

8084 Efficiency for the BOM-ATM conversion process is 78.5 percent based on a coal input of 13,800 Btu/lb and gas and tar output of 10,832 Btu/lb (8016)

8085 Efficiency of the BOM-ATM conversion process of 73.3 percent based on a coal input of 9226 Btu/lb and gas and tar output of 6758 Btu/lb (8016).

8086 Ancillary energy for the ATC conversion process is 3.59E+09 Btu, based on a 12MW consumption for a 1000 MW plant, and a total process efficiency of 29 percent (8029). For a 1.00E+12 Btu input, ancillary energy is 3.59E+09 Btu.

8087 Dust loading on the cleaned gas from the Koppers-Totzek process is approximately 0.0020 grains/SCF (8024,7). 1.0 ton of Central coal, North Appalachian coal or Northwestern coal will produce 5.95E04 SCF (8024,14), 6.64E04 SCF (8024,14) and 4.38E04 SCF (8023) of gas respectively. Based on the above particulate emission for electrical generation based on 1.00E12 Btu of gas input is as follows, in tons:

Central Coal	Northern Appalachian	Northwest Coal
4.62E-01	5.03E-01	4.56E-01

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8088 Ancillary energy for the Kopper-Totzek conversion process is based on 15 MW for a 1000 MW plant (8029). For the Central, Northern Appalachia, and Northwest coals, the total process efficiency is 32 percent, 32.8 percent, and 29.8 percent. Based on this the ancillary energy on a 1.00E+12 Btu basis is 4.81, 4.92, and 4.48E+09 Btu respectively.

8089 Ancillary energy for the boiler generation cycle is 3.37E+09 Btu based on footnote 8062. Energy required for steam and power generation is 2590 KW (8012,II-D-5) for an input of 2.30E+13 Btu. No air compression is required. On a 1.00E+12 Btu basis,ancillary energy is 3.37E+09 Btu.

8090 Potential sources of water effluent from the Koppers-Totzek process are boiler blowdown, raw gas cooling system and overfill of clarifier. For a 1.00E12 Btu input of coal 1.33E+06 gallon of boiler blowdown will be produced containing 40.0 PPM suspended solids, maximum of 30.0 MG/L BOD and 25.0 MG/L COD. This water will be cooled to 85-100F and routed to clarifier. Water from raw gas cooling will follow the same route. The clarifier will require an additional 80.0 gal/minute in makeup water because of evaporation losses in quenching of ash from gasifier. The clarifier will contain approximately 250 PPM of total dissolved solids. From the clarifier the water will be filtered and treated, then recycled. Effluent = 0.00.

8091 Capital cost of a combined cycle gas-fired power plant is 4.15E+07 dollars for a 363 MW plant (8020,16). Plant efficiency is 40 percent. With a fixed charge rate of 10 percent, the annualized capital cost is 1.53E+05 dollars/1.00E+12 Btu in. Assumes a 100 percent plant load factor. This cost does not include the cost of the equipment to produce the low Btu fuel gas.

8092 Capital cost for the ATC coal conversion process only associated with a 1000 MW plant is 1.80E+07 dollars (8022). Based on a 1.00E+12 Btu basis and plant efficiencies of 78.8, 73.6, and 81.0 for the Central, Northern Appalachia, and Northwest coals the capital cost are 4.70, 4.40, and 4.88E+04 dollars respectively, (annualized with a 10 percent fixed charge rate). Assumes a 100 percent plant load factor.

8093 Capital cost for the BOM-Atmospheric process is 1.08E+07 dollars for a 150 ton/hour plant (8020). Based on a 1.00E+12 Btu input (see footnotes 8042-8044 for equivalent tons of coal) and 8760 hr/yr for the Central, Northern Appalachia, and Northwest coals, the capital cost are 3.43, 3.13, and 4.68E+04 dollars respectively (annualized with a 10 percent fixed charge rate).

8094 Capital cost for the BOM-Pressurized conversion activity is 2.59E07 dollars for a 150 ton/hour plant (8026). Based on a 1.00E+12 Btu input (see footnote 8039-8041 for equivalent tons of coal) and 8760 hr/yr for Central, North Appalachia, and Northwest coals, for capital costs are 8.23E04, 7.48E04, and 1.12E+05 dollars respectively (annualized with a 10 percent fixed charge rate).

8095 Capital cost for the Koppers-Totzek conversion process is 8.6E+07 dollars for a 1.40E11 Btu out/day plant (8024). Based on a 1.00E12 Btu in basis, 365 d/yr, and plant efficiencies of 81.1, 82.0, and 74.4 percent for Central, Northern Appalachia, and Northwest coals the costs are 1.36, 1.36, and 1.25E05 respectively (annualized with a 10 percent fixed charge rate).

8096 Capital cost for the Lurgi conversion process only associated with a 333 MW plant is 1.65E07 dollars (8020,16). Based on a total plant efficiency of 30.3 percent and on a 1.00E12 Btu basis the capital cost is 5.02E04 dollars (annualized with a 10 percent fixed charge rate). Assumes a 100 percent plant load factor.

8097 Operating cost for the BOM-Pressurized system is based on a cost of 4.3E+06 dollars/yr for a 150 ton/hr plant (8760 hr/yr) (8010). For a 1.00E12 Btu input and coal heating value of 12,050, 13,800, and 9,226 Btu/lb for the Central, Northern Appalachia, and Northwestern coal the annual operating costs are 1.35, 1.19, and 1.78E05 dollars respectively. Coal cost not included.

8098 Operating cost for the BOM-Atmospheric system is 1.85E+06 dollars/yr for a 150 ton/hour plant (8760 hr/yr) (8010). As in footnote 8097 operating cost are 5.77, 5.05, and 7.58E04 for the Central, North Appalachia, and Northwest coals respectively.

8099 Operating cost for the Lurgi Fuel Gas Production system is based on 19.4 percent of the total plant input (8012). For a feed for gas production of 207.8 tons/hour (8760 hr/yr) of Northwestern coal, operating costs are 4.83E06 $/yr. On a 1.00E12 Btu input operating costs are 1.44E05 dollars. Coal cost not included.

8100 NO_x emissions for a combined cycle will primarily come from the gas fired turbine. From (8028 ,10), a dry turbine system will emit 150 ppm (vol) when fired at 2000F using natural gas. From tests performed, low-Btu gas will emit only 15 ppm (vol) (8028 ,11). Based on this, how much is emitted depends upon the amount of flue gas produced. The amount of gas produced by process and coal type is as follows -

BOM Press. - Northwest 3.36E10 scf/1.00E12 Btu
BOM Press. - North. Appl. 1.06E10 scf/1.00+12 Btu
BOM Press. - Central 3.19E10 scf/1.00E12 Btu
Koppers-Totzek - Northwest 1.61E10 scf/1.00E12 Btu
Koppers-Totzek - North. Appl. 2.27E10 scf/1.00E12 Btu
Koppers-Totzek - Central 2.79E10 scf/1.00E12 Btu

From the above, the emissions are as follows -

BOM Press.	- Northwest	3.24E01 ton
BOM Press.	- North. Appl.	1.03E01 ton
BOM Press.	- Central	3.94E01 ton
K-T	- Northwest	1.59E01 ton
K-T	- North. Appl.	1.96E01 ton
K-T	- Central	2.37E01 ton

8101 Effluent from the Lurgi process will be nill. All water will be recycled where applicable and the rest will go to evaporation ponds (8031).

8102 Sources of air emission from the Koppers-Totzek conversion process, using Northwestern coal, are the coal fired thermal dryer and the Claus plant. In thermal drying, 1.31E03 ton is consumed in drying, see footnote 8000. The emissions are as follows (see footnote 8053): 5.42E00 ton particulate, 5.15 ton of NO_x, 4.28E-01 ton of SO_x, 5.50 ton of hydrocarbon, and 3.71E00 ton of CO.

Air emission from the Claus plant depends upon the amount of sulfur in the gas feed to the plant. 1.0 lb of Northwestern coal will produce 4.80E-02 lb of H_2S. Of this 90.0 percent is removed in the Rectisol unit yielding a feed of 4.32E-02 lb to the Claus. The Claus with Stretford tail gas clean up will vent 4.32-04 ton SO_x/ton of coal fed to gasifier. 4.30E04 ton of coal/1.00E12 Btu is fed to gasifier, therefore SO_x = 1.76E01 ton.

8103 Assuming that a low temperature boiler is used, NO_x = 25.0 ppm (see footnote 8003). The BOM Atmospheric Process using, Central, Northern Appalachia, and Northwestern coal will produce 4.44 lb/lb coal, 4.96 lb/lb coal and 4.08 lb/lb respectively. These gases have a heating value of 8.97E03 Btu, 8.96E03 Btu, and 6.04E03 Btu. Inputing 1.00+12 Btu of these gases to the boiler, will produce NO_x emissions as follows:

Central	Northern Appalachia	Northwestern
5.69E00 ton	6.36E00 ton	7.76E00 ton

8104 Air pollutants for the National Average low Btu coal gasification activity are the arithmetic average of the process utilizing a Central, Northern Appalachia, and Northwest coal. For calculations see individual process and footnote.

8105 Air pollutants from the electrical generation activity using low Btu fuel gas are the arithmetic average of the process utilizing a Central, Northern Appalachian, and Northwest coal. For calculations see individual regional coals.

8106 Land impact for low Btu gasification and electrical generation is the arithemetic mean of the individual processes utilizing Central, Northern Appalachian, and Northwest coal. For calculations see individual coal regions.

8107 Solid waste for coal gasification is the arithmetic mean of the individual processes utilizing Central, Northern Appalachian, and Northwest coals. For calculations see individual coal regions.

8108 Ancillary energy for the low Btu gasification processes is the arithemetic mean of the processes utilizing Central, Northern Appalachian, and Central coals. For calculations see individual regions.

8109 Primary efficiency for the low Btu gasification processes is the arithemetic mean of the processes utilizing Central, Northern Appalachian, and Northwestern coals. For calculations see individual regions.

8110 Cost for the gasification and electrical generation activities is the arithemetic mean of the processes utilizing Central, Northern Appalachian, and Northwest coals. For calculations see individual regions.

8111 SO_x emissions from the Koppers-Totzek electrical generation process utilizing Northwest coal occurs in the boiler step. Assuming complete combustion of the H_2S and COS entering the system 10 percent x 2.59E+02 = 2.59E+01 tons of SO_x is emitted. See footnote 8053.

8112 From footnotes 2907 and 3905 the total annualized capital cost for a controlled gas fired power plant is 2.35E05 $/1.0E12 Btu in. This is for a 60P load factor. For a 100P load factor the annualized capital investment is 1.41E05 $/1.0E12 Btu in. This cost does not include the cost of the equipment to produce the low Btu fuel gas.

IV. HIGH BTU GASIFICATION OF COAL

A. Introduction

The environmental impacts, efficiencies, and costs associated with the production of high Btu (greater than 900 Btu/SCF) synthetic natural gas from coal are given in Table 2 of this report. Each data entry is based on an energy input of coal equivalent to 10^{12}Btu/yr. The specific coal utilized and its energy equivalent is contained in the first footnote for each of the regional and national cases. All table entries have been derived for a "controlled" environmental condition. The nature and magnitude of coal gasification operations is such that stringent environmental control must be practiced.

The six processes which comprise the High Btu Gasification Activity are:

1. Lurgi Process
2. Hygas-Electrothermal Process
3. Hygas-Steam Oxygen Process
4. Bigas Process
5. Synthane Process
6. CO_2 Acceptor Process

Also included is a Typical New Process which represents conceptually a combination of the best features of the "new generation" processes - Hygas, Bigas, and Synthane. The CO_2 Acceptor Process was not included in this average, since its process operation is quite different from the rest.

Impacts were developed for three regional coals, with a National Average case synthesized from the regional data. The Lurgi Process is limited to weakly caking bituminous coals and was, therefore, not considered in the Northern Appalachia region where many of the coals exhibit strong caking properties. The CO_2 Acceptor Process, on the other hand, operates primarily on a lignite coal and was, therefore, only considered in the Northwest region with a lignite feed. A principal advantage of the "new generation" processes is their ability to handle the range of coals from bituminous to lignite. All of the cost data shown in Table 2 is based on a 90 percent plant load factor, or 328 operating days/yr. The values presented in this table are based on data accumulated during the Fall of 1973.

The following is a brief description of the individual processes:

1. Lurgi Process

The Lurgi Process (Figure 14) utilizes a high pressure (300-500 PSIG), fixed-bed, nonslagging, steam-oxygen gasifier to produce a synthesis gas stream from coal. The coal enters through a lock-hopper system at the top of the gasifier, reacts with the steam and oxygen as it moves downward on a revolving grate and leaves as ash for disposal through the ash lock hoppers. The synthesis gas stream leaves the gasifier at a temperature of 1100°F and is subsequently cooled and scrubbed of tars and oils. The gas stream composition is then adjusted in the shift conversion step, scrubbed of its acidic gases (CO_2 and H_2S), and methanated. The Lurgi Process is currently the only commercially available SNG system.

2. Hygas-Electrothermal Process

The Hygas Process (Figure 15) features hydrogasification in two countercurrent stages for the production of synthesis gas from coal. The coal is pretreated (if required), slurried with an aromatic oil and pressurized (1000 PSIG) for introduction into the gasification reactor. As the coal enters the reactor, the slurry oil is vaporized and the coal falls through a low-temperature reaction zone where methane is produced primarily from the coal volatile matter. The devolatized coal then passes into the high-temperature zone where it is hydrogasified by reaction with hydrogen and steam to form additional methane. The remaining coal or char containing significant amounts of unreacted carbon is used to generate the hydrogen-rich gas required in the hydrogasification process. In the Electrothermal Process, the char is reacted with steam to produce this hydrogen-rich gas with electric resistance heating supplying the energy needed to sustain the reactions. The residual char is then used in plant boilers for the production of steam and electricity. The hot synthesis gas leaving the hydrogasifier is cooled, its composition adjusted, and scrubbed free of acidic gases. The gas is then methanated to produce pipeline quality gas. The Hygas Process is currently the most advanced of the "new generation" processes with a successful pilot plant in operation since the end of 1972.

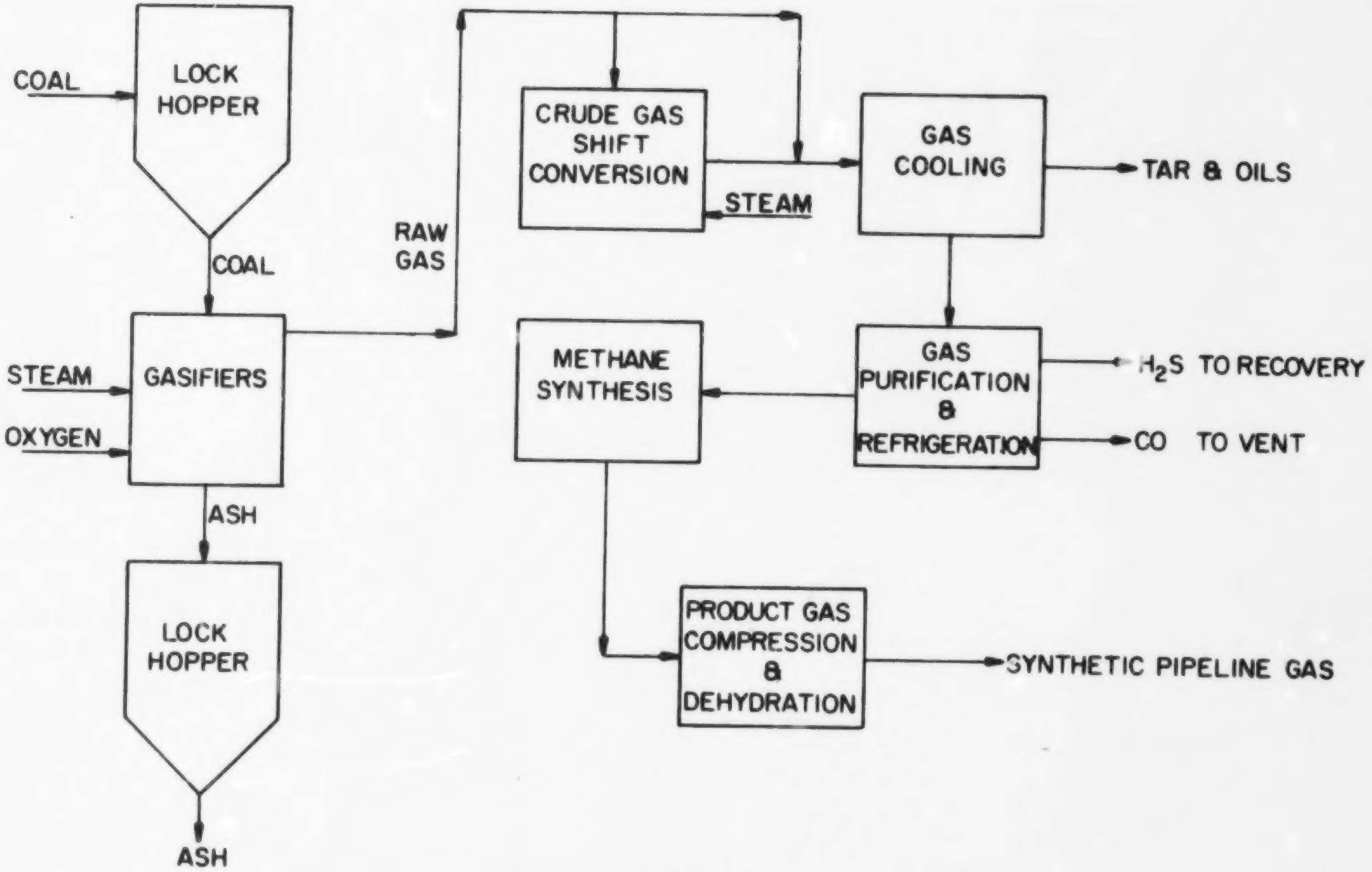
COAL
LOCK HOPPER
COAL
STEAM
GASIFIERS
OXYGEN
ASH
LOCK HOPPER
ASH
RAW GAS
CRUDE GAS SHIFT CONVERSION
STEAM
GAS COOLING
TAR & OILS
GAS PURIFICATION & REFRIGERATION
H_2S TO RECOVERY
CO TO VENT
METHANE SYNTHESIS
PRODUCT GAS COMPRESSION & DEHYDRATION
SYNTHETIC PIPELINE GAS

Figure 14. Lurgi Process of High Btu Coal Gasification (Ref. 8310)

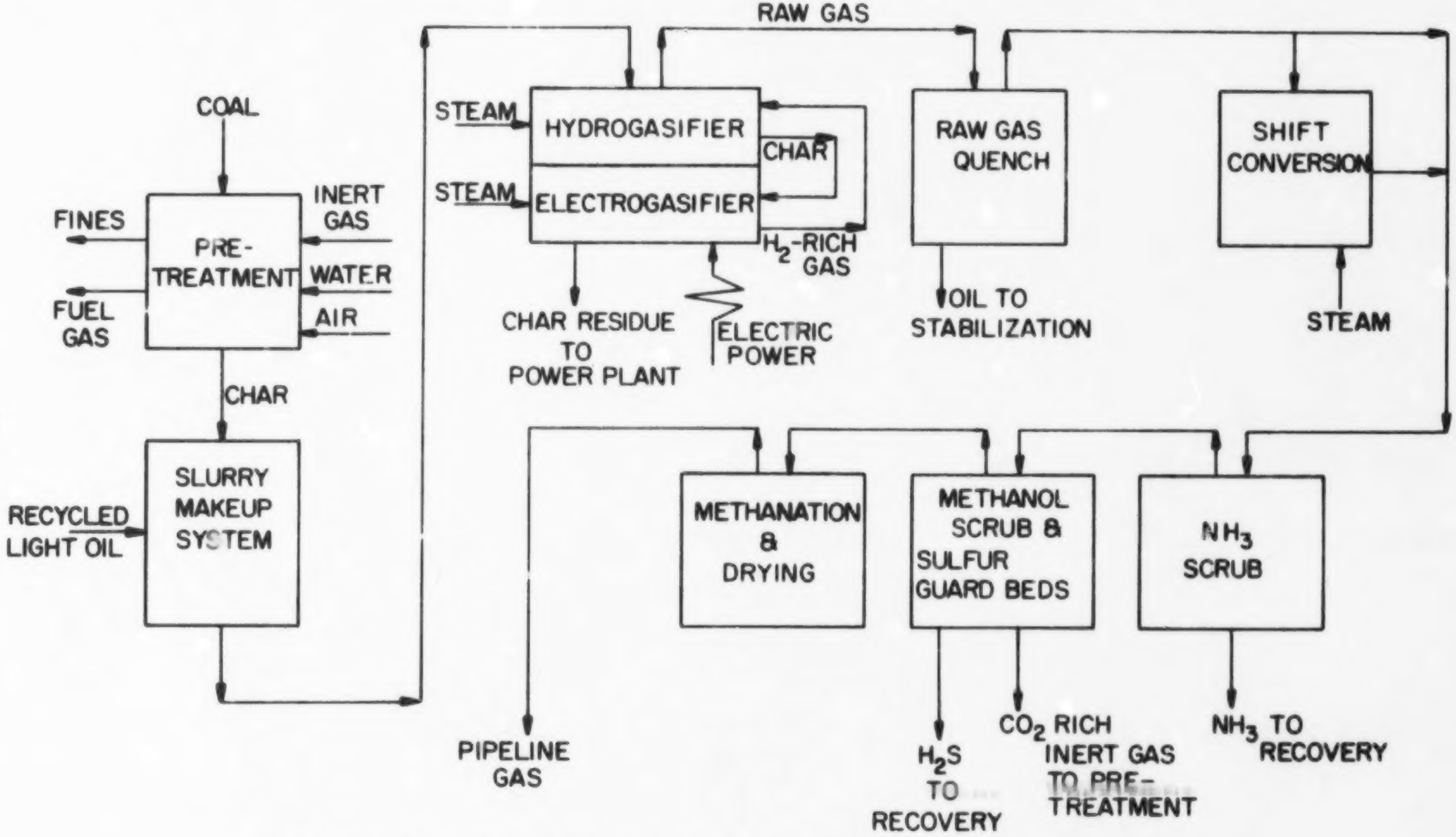
COAL
FINES
FUEL GAS
PRE-TREATMENT
INERT GAS
WATER
AIR
CHAR
SLURRY MAKEUP SYSTEM
RECYCLED LIGHT OIL
STEAM
STEAM
HYDROGASIFIER
ELECTROGASIFIER
CHAR
H_2-RICH GAS
CHAR RESIDUE TO POWER PLANT
ELECTRIC POWER
RAW GAS
RAW GAS QUENCH
OIL TO STABILIZATION
SHIFT CONVERSION
STEAM
METHANATION & DRYING
METHANOL SCRUB & SULFUR GUARD BEDS
NH_3 SCRUB
PIPELINE GAS
H_2S TO RECOVERY
CO_2 RICH INERT GAS TO PRE-TREATMENT
NH_3 TO RECOVERY

Figure 15. Hygas Electrothermal Process of High Btu Coal Gasification (Ref. 8308)

3. Hygas-Steam Oxygen Process

This process differs from the Hygas-Electrothermal Process only in the manner in which the hydrogen-rich gas is generated for the hydrogasifier section (see Figure 16). In the Steam Oxygen Process the char is fluidized in an oxygen-steam mixture and the heat required for the steam-char reaction is supplied by partial combustion of the char. The residual char is then used as boiler fuel.

4. Bigas Process

The Bigas Process (Figure 17) utilizes a two-stage, super-pressure (1000-1500 PSI), entrained bed, oxygen blown gasifier for the gasification of coal. The coal is pulverized and fed into the top section of the two-stage gasifier where it is contacted by a rising steam of hot synthesis gas produced in the lower section. The coal is partially converted into a gaseous mixture in this section and is entrained in the gas stream and removed from the gasifier. The gas and char are separted and the char returned to the lower, stage 1, section of the gasifier. Here the char is completely gasified under slagging conditions with oxygen and steam to produce the synthesis gas stream for stage two. The product gas is subsequently upgraded to pipeline quality gas.

5. Synthane Process

In this process pretreatment of caking coals and gasification are accomplished in one reactor (see Figure 18). The coal is fed into the gasifier through lock hoppers and reacted with steam and oxygen under pressure (40-70 ATM) in a two zone fluidized bed system. A char residue is discharged from the gasifier and subsequently used as boiler fuel. The synthesis gas is adjusted, cleaned, and methanated to produce pipeline quality gas.

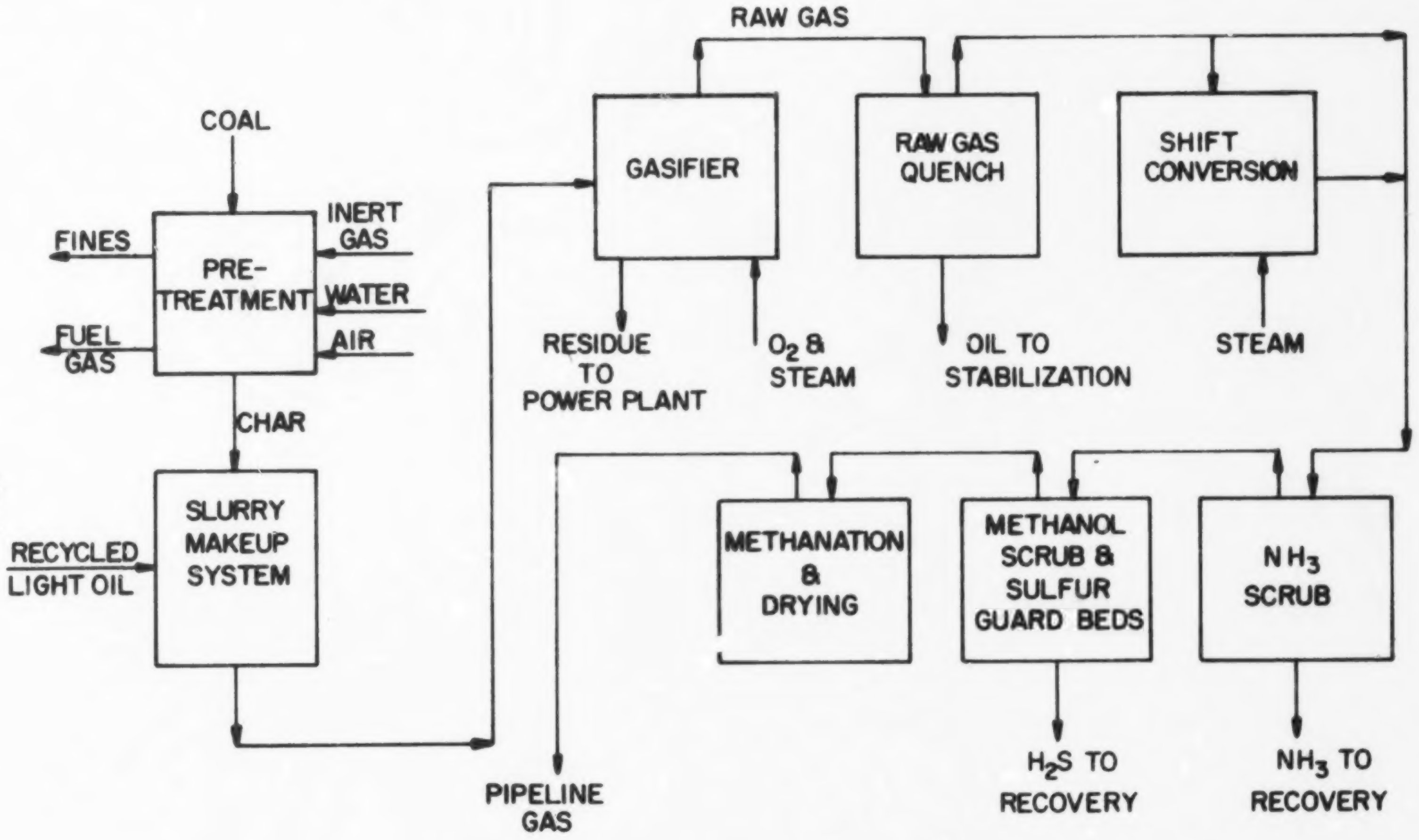
RAW GAS
COAL
FINES
PRE-TREATMENT
INERT GAS
WATER
FUEL GAS
AIR
CHAR
SLURRY MAKEUP SYSTEM
RECYCLED LIGHT OIL
GASIFIER
RESIDUE TO POWER PLANT
O_2 & STEAM
RAW GAS QUENCH
OIL TO STABILIZATION
SHIFT CONVERSION
STEAM
METHANATION & DRYING
METHANOL SCRUB & SULFUR GUARD BEDS
NH_3 SCRUB
PIPELINE GAS
H_2S TO RECOVERY
NH_3 TO RECOVERY

Figure 16. Hygas Steam-Oxygen Process of High Btu Coal Gasification (Ref. 8308)

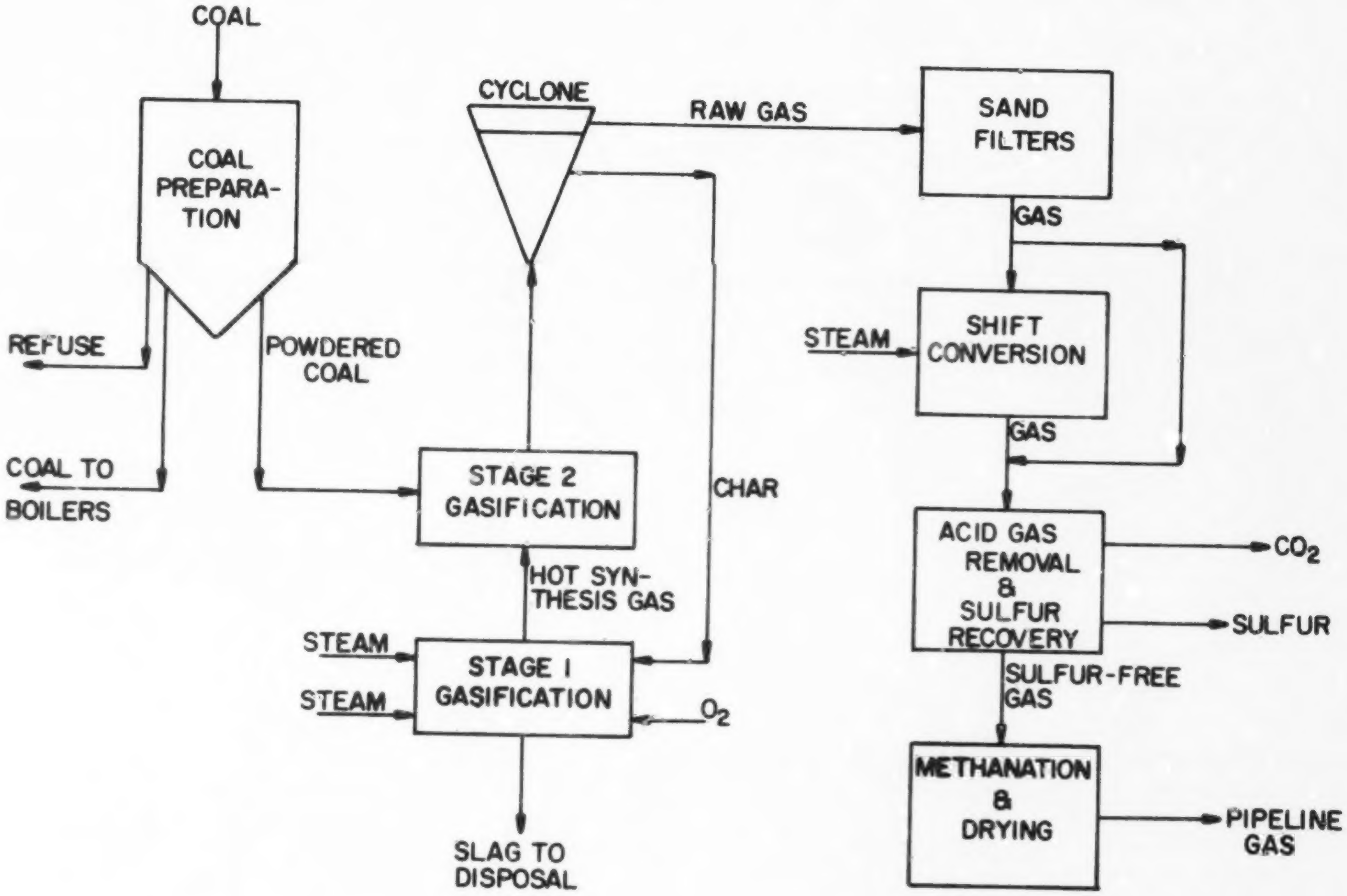
COAL
COAL PREPARA-TION
REFUSE
COAL TO BOILERS
POWDERED COAL
CYCLONE
RAW GAS
STAGE 2 GASIFICATION
HOT SYN-THESIS GAS
CHAR
STEAM
STEAM
STAGE I GASIFICATION
O_2
SLAG TO DISPOSAL
SAND FILTERS
GAS
STEAM
SHIFT CONVERSION
GAS
ACID GAS REMOVAL & SULFUR RECOVERY
CO_2
SULFUR
SULFUR-FREE GAS
METHANATION & DRYING
PIPELINE GAS

Figure 17. Bigas Process of High Btu Coal Gasification (Ref. 8305)

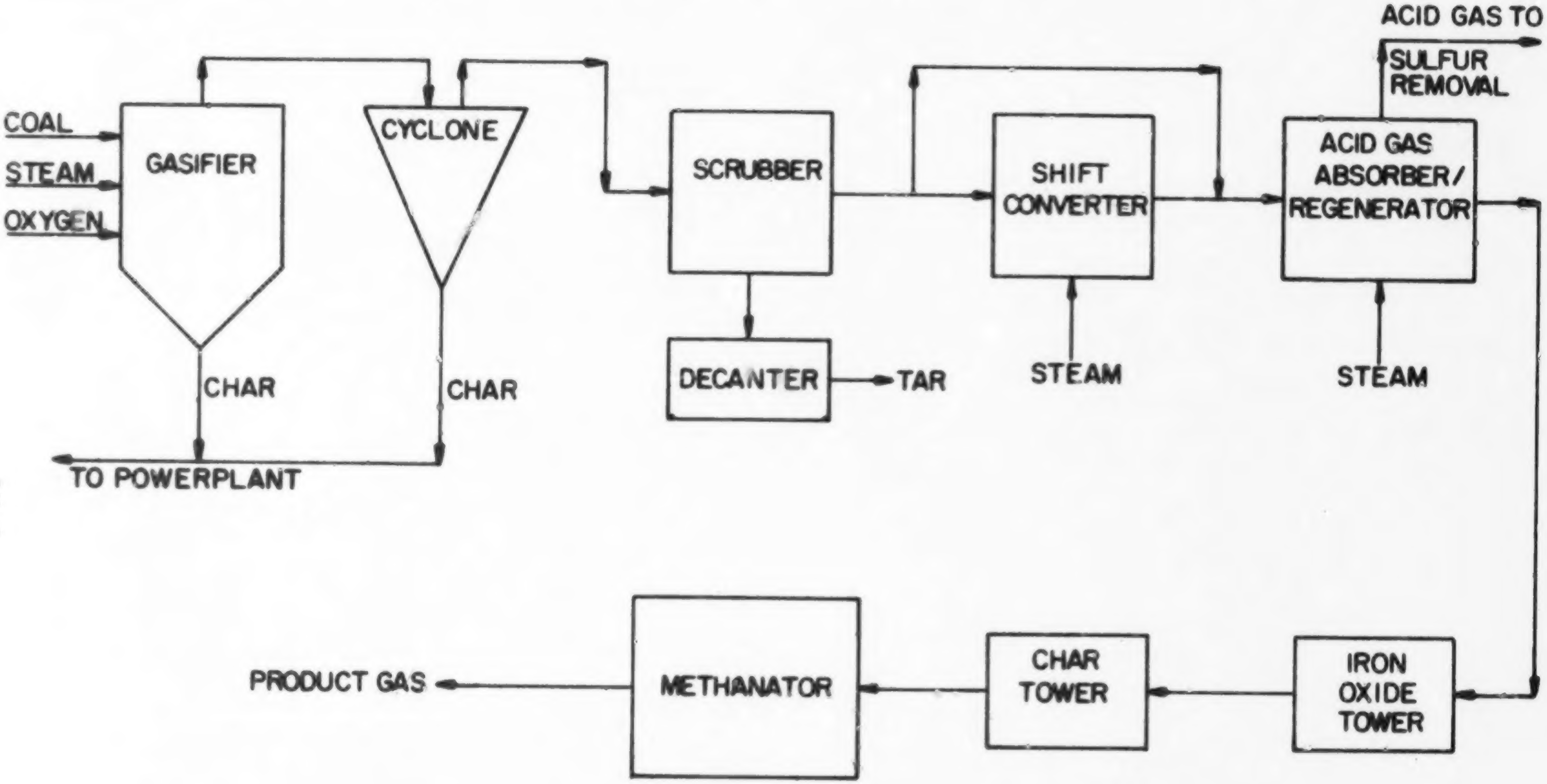
COAL
STEAM
OXYGEN
GASIFIER
CYCLONE
CHAR
CHAR
TO POWERPLANT
SCRUBBER
DECANTER
TAR
SHIFT CONVERTER
STEAM
ACID GAS ABSORBER/ REGENERATOR
STEAM
ACID GAS TO SULFUR REMOVAL
IRON OXIDE TOWER
CHAR TOWER
METHANATOR
PRODUCT GAS

Figure 18. Synthane Process of High Btu Coal Gasification (Ref. 8309)

6. CO_2 Acceptor Process

The CO_2 Acceptor Process (Figure 19) operates only on lignite and subbituminous coals and employs a unique circulating system of dolomite to provide process heat and synthesis gas cleanup. Dried lignite enters the devolatilizer together with calcined dolomite from the regenerator, steam, and hydrogen-rich gas from the gasifier. The lignite is devolatilized and methane produced from the volatile matter with heat of reaction supplied by the $CaO + CO_2$ reaction. The raw gas stream leaving the devolatilizer is upgraded to SNG. The lignite char is transferred to the gasifier along with dolomite to complete the gasification operation. The remaining lignite char is then transferred to the dolomite regenerator and used as fuel for calcining the spent dolomite from the devolatilizer and gasifier.

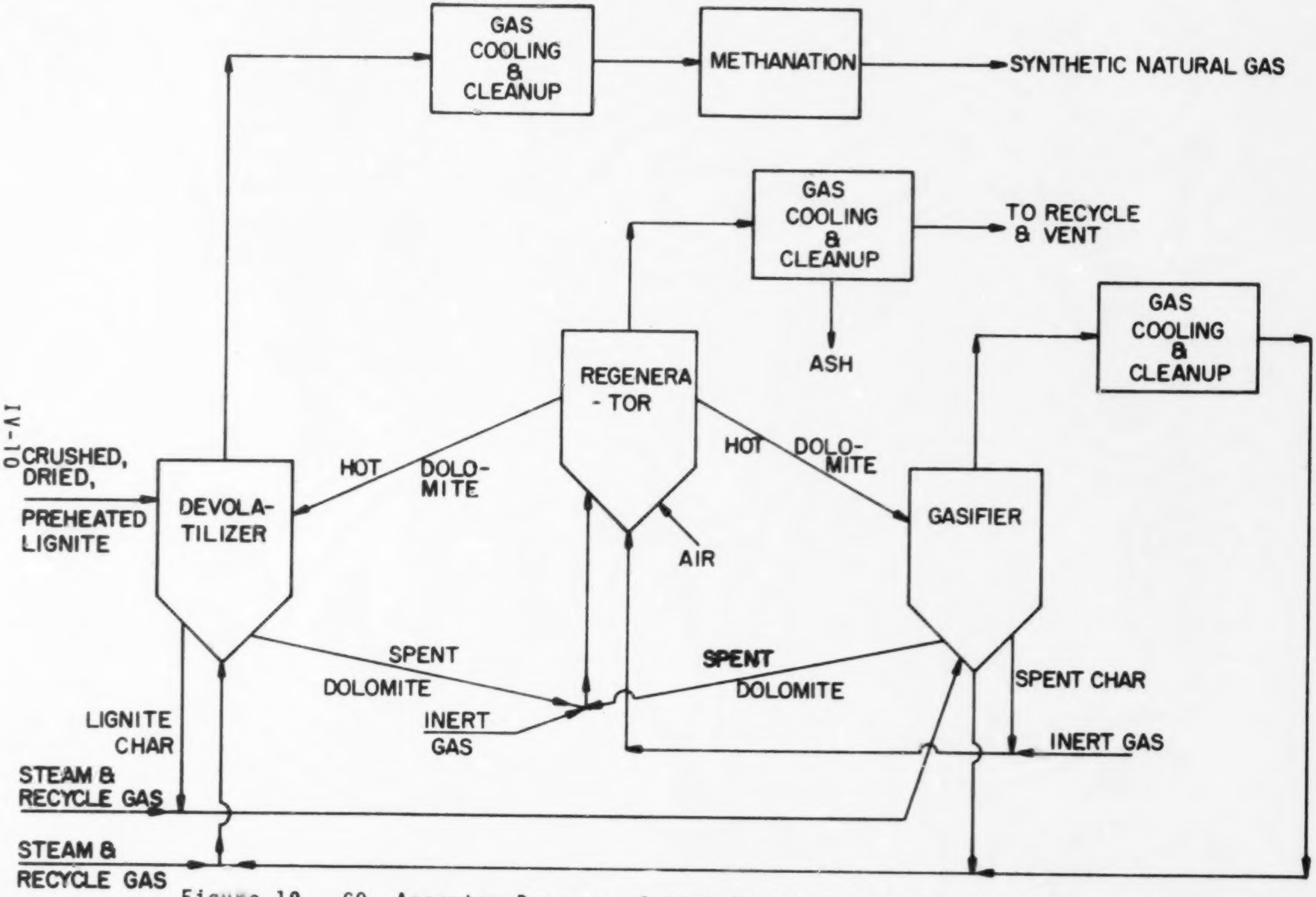
GAS COOLING & CLEANUP
METHANATION
SYNTHETIC NATURAL GAS
GAS COOLING & CLEANUP
TO RECYCLE & VENT
ASH
GAS COOLING & CLEANUP
CRUSHED, DRIED,
PREHEATED LIGNITE
DEVOLA-TILIZER
HOT DOLO-MITE
REGENERA-TOR
HOT DOLO-MITE
GASIFIER
AIR
SPENT DOLOMITE
SPENT DOLOMITE
SPENT CHAR
INERT GAS
INERT GAS
LIGNITE CHAR
STEAM & RECYCLE GAS
STEAM & RECYCLE GAS

Figure 19. CO_2 Acceptor Process of High Btu Coal Gasification (Ref. 8321)

B. Impact Data Table and Footnotes

CONTROLLED

FUEL	REGION
COAL	AS INDICATED

ROW	MNE-MON.	ACTIVITY PROCESS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX COL 12)												AIR P		
					DISSOLVED SOLIDS												
			ACIDS	BASES	PO_4	NO_3	OTHER	TOTAL (DS)	SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	SO_x
1		NORTHERN APPALACHIA															
2	GASHI	GASIFICATION HIGH BTU															
3	TYPNW	TYPICAL NEW PROCESS	0999	0999	0999	0999	0999	3.50-01 5 8420	9.49-02 5 8421	8.28-02 5 8421	3.60-01 5	0999	0999	0.00+00 2 8427	9.03+00 4 8418	7.62+01 4 8418	2.00+01 4
4	HYGEL	HYGAS ELECTROTHERMAL	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8427	1.80+01 4 8402	9.06+01 4 8402	2.13+01 4
5	HYGST	HYGAS STEAM OXYGEN	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8427	3.06+00 4 8406	6.01+01 4 8406	2.63+01 4
6	BIGAS	BIGAS	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8427	3.66+00 4 8416	5.66+01 4 8414	1.75+01 4
7	SYNTH	SYNTHANE	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8427	1.54+01 4 8410	9.58+01 4 8410	1.87+01 4
8																	
9		CENTRAL															
10	GASHI	GASIFICATION HIGH BTU															
11	LURGI	LURGI	0999	0999	0999	0999	0999	4.31-01 5 8471	9.00-01 5 8471	4.26-01 5 8471	4.44+01 5	0999	0999	0.00+00 2 8483	3.65+00 4 8468	7.33+01 4 8468	1.68+01 4
12	TYPNW	TYPICAL NEW PROCESS	0999	0999	0999	0999	0999	3.86-01 5 8476	1.02-01 5 8476	8.90-02 5 8476	3.88+01 5	0999	0999	0.00+00 2 8483	1.00+01 4 8473	8.53+01 4 8473	6.61+01 4
13	HYGEL	HYGAS ELECTROTHERMAL	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8483	1.37+01 4 8452	9.93+01 4 8452	1.81+01 4
14	HYGST	HYGAS STEAM OXYGEN	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8483	6.88+00 4 8456	6.81+01 4 8456	6.29+01
15	BIGAS	BIGAS	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8483	6.75+00 4 8464	6.26+01 4 8464	8.15+01 4
16	SYNTH	SYNTHANE	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8483	1.47+01 4 8460	1.11+02 4 8460	5.18+01 4
17																	
18		NORTHWEST															
19	GASHI	GASIFICATION HIGH BTU															
20	LURGI	LURGI	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2	0.00+00 2 8375	0.00+00 2 8375	0.00+00 2 8393	2.05+00 4 8372	7.69+01 4 8372	5.59+00 4
21	TYPNW	TYPICAL NEW PROCESS	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2	0.00+00 2 8385	0.00+00 2 8385	0.00+00 2 8393	8.13+00 4 8382	8.54+01 4 8382	9.19+00 4
22	HYGEL	HYGAS ELECTROTHERMAL	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2	0.00+00 2 8355	0.00+00 2 8355	0.00+00 2 8393	1.04+01 4 8352	1.00+02 4 8352	7.18+00 4
23	HYGST	HYGAS STEAM OXYGEN	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2	0.00+00 2 8360	0.00+00 2 8360	0.00+00 2 8393	5.71+00 4 8357	6.83+01 4 8357	5.90+00 4
24	BIGAS	BIGAS	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2	0.00+00 2 8370	0.00+00 2 8370	0.00+00 2 8393	3.42+00 4 8367	5.83+01 4 8367	1.41+01 4
25	SYNTH	SYNTHANE	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2	0.00+00 2 8365	0.00+00 2 8365	0.00+00 2 8393	1.30+01 4 8362	1.15+02 4 8362	9.63+00 4
26	COACC	CO_2 ACCEPTOR	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2	0.00+00 2 8380	0.00+00 2 8380	0.00+00 2 8393	3.31+00 4 8377	3.81+01 4 8377	6.17+01 4
27																	
28		NATIONAL AVERAGE															
29	GASHI	GASIFICATION HIGH BTU															
30	LURGI	LURGI	0999	0999	0999	0999	0999	2.16-01 5 8311	4.50-01 5 8311	2.11-01 5 8311	2.23+01 5	0999	0999	0.00+00 2 8312	2.85+00 4 8308	7.51+01 4 8308	2.12+01 4
31	TYPNW	TYPICAL NEW PROCESS	0999	0999	0999	0999	0999	2.48-01 5 8333	6.56-02 5 8333	5.73-02 5 8333	2.49+01 5	0999	0999	0.00+00 2 8312	9.06+00 4 8330	8.24+01 4 8330	3.17+01 4
32	HYGEL	HYGAS ELECTROTHERMAL	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 [illegible]	1.27+01 4 8314	9.66+01 4 8316	3.28+01 4
33	HYGST	HYGAS STEAM OXYGEN	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8312	5.21+00 4 8318	6.55+01 4 8318	2.97+01 4
34	BIGAS	BIGAS	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8312	3.94+00 4 8322	5.84+01 4 8322	3.77+01 4
35	SYNTH	SYNTHANE	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0999	0.00+00 2 8312	1.44+01 4 8326	1.09+02 4 8326	2.67+01 4
36	COACC	CO_2 ACCEPTOR	0.00+00 2 8333	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2	0.00+00 2 8338	0.00+00 2 8338	0.00+00 2 8312	3.31+00 4 8335	3.81+01 4 8335	6.17+01 4
37																	
38																	
39																	
40																	
41																	
42																	
43																	
44																	
45																	
46																	
47																	
48																	
49																	
50																	
51																	
52																	
53																	
54																	
55																	

HITMAN

12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
THERMAL BTU/10^{12} BTU	PARTICULATES	NO_x	SO_x	HYDROCARBONS	CO	ALDEHYDES ETC	TOTAL	SOLIDS TONS/10^{12} BTU	LAND $\left(\frac{\text{ACRE-YR}}{10^{12}\text{ BTU}}\right)$	DEATHS / 10^{12} BTU	INJURIES / 10^{12} BTU	MAN-DAYS LOST/10^{12} BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY (BTU/10^{12} BTU)	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
																			2
.00+00 2 8427	9.33+00 4 8418	1.42+01 4 8418	2.00+01 4 8418	1.16+00 4 8418	4.02+00 4 8418	3.99-01 4 8418	1.11+02 4	6.53+03 2 8419	2.56-00 3 8420	0999	0999	0999	2091	5.87-01 2 8417	0.00+00 2 8417	1.73+05 3 8426	8.94+04 3 8426	2.62+05 3	3
.00+00 2 8427	1.40+01 4 8402	9.04+01 4 8402	2.33+01 4 8402	1.27+00 4 8402	4.61+00 4 8402	3.96-01 4 8402	1.36+02 4	6.46+03 2 8403	2.63+00 3 8404	0999	0999	0999	2091	5.72-01 2 8401	0.00+00 2 8401	1.83+05 3 8423	8.54+04 3 8423	2.73+05 3	4
.00+00 2 8427	3.04+00 4 8406	6.01+01 4 8406	2.03+01 4 8406	7.83-01 4 8406	2.92+00 4 8406	3.63-01 4 8406	8.75+01 4	6.50+03 2 8407	2.53+00 3 8408	0999	0999	0999	2091	5.87-01 2 8405	0.00+00 2 8405	1.59+05 3 8424	7.55+04 3 8424	2.35+05 3	5
.00+00 2 8427	3.66+00 4 8414	5.44+01 4 8414	1.75+01 4 8414	9.07-01 4 8414	3.02+00 4 8414	4.00-01 4 8414	7.99+01 4	6.59+03 2 8415	2.46+00 3 8416	0999	0999	0999	2091	6.56-01 2 8413	0.00+00 2 8413	1.89+05 3 8422	1.15+05 3 8422	3.04+05 3	6
.00+00 2 8427	1.56+01 4 8410	[illegible] 4 8410	1.87+01 4 8410	1.67+00 4 8410	5.56+00 4 8410	6.30-01 4 8410	1.82+02 4	6.56+03 2 8411	2.46+00 3 8412	0999	0999	0999	2091	5.35-01 2 8409	0.00+00 2 8409	1.55+05 3 8425	8.18+04 3 8425	2.37+05 3	7
																			8
																			9
																			10
.00+00 2 8483	3.65+00 4 8468	7.33+01 4 8468	2.68+01 4 8468	1.22+00 4 8468	4.07+00 4 8468	4.48-01 4 8462	1.19+02 4	5.27+03 2 8469	2.41+00 3 8470	0999	0999	0999	2091	5.61-01 2 8467	0.00+00 2 8467	1.90+05 3 8482	8.11+04 3 8482	2.71+05 3	11
.00+00 2 8483	1.00+01 4 8473	8.53+01 4 8473	4.61+01 4 8473	1.29+00 4 8473	4.50+00 4 8473	4.28-01 4 8473	1.63+02 4	5.29+03 2 8474	2.33+00 3 8475	0999	0999	0999	2091	6.20-01 2 8472	0.00+00 2 8472	1.93+05 3 8481	9.00+04 3 8481	2.84+05 3	12
.00+00 2 8483	1.37+01 4 8452	9.93+01 4 8452	6.87+01 4 8452	1.40+00 4 8452	5.07+00 4 8452	4.28-01 4 8452	1.88+02 4	5.24+03 2 8453	2.62+00 3 8454	0999	0999	0999	2091	6.22-01 2 8451	0.00+00 2 8451	2.11+05 3 8478	8.78+04 3 8478	2.99+05 3	13
.00+00 2 8483	4.48+00 4 8456	6.81+01 4 8456	6.29+01 4 8456	8.95-01 4 8456	3.35+00 4 8456	3.94-01 4 8456	1.43+02 4	5.25+03 2 8457	2.75+00 3 8458	0999	0999	0999	2091	6.37-01 2 8455	0.00+00 2 8455	1.80+05 3 8479	7.80+04 3 8479	2.58+05 3	14
.00+00 2 8483	4.75+00 4 8464	6.24+01 4 8464	8.15+01 4 8464	1.00+00 4 8464	3.15+00 4 8464	4.23-01 4 8464	1.54+02 4	5.34+03 2 8465	3.05+00 3 8466	0999	0999	0999	2081	6.74-01 2 8463	0.00+00 2 8463	2.04+05 3 8477	1.14+05 3 8477	3.18+05 3	15
.00+00 2 8483	1.47+01 4 8460	1.11+02 4 8460	5.18+01 4 8460	1.86+00 4 8460	6.21+00 4 8460	4.65-01 4 8460	1.86+02 4	5.33+03 2 8461	2.87+00 3 8462	0999	0999	0999	2091	5.88-01 . 8459	0.00+00 2 8459	1.75+05 3 8480	8.37+04 3 8480	2.99+05 3	16
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.00+00 2 8391	2.05+00 4 8372	7.69+01 4 8372	5.59+00 4 8372	1.28+00 4 8372	4.27+00 4 8372	2.90-01 4 8372	9.04+01 4	3.73+03 2 8373	3.78+00 3 8374	0999	0999	0999	2091	6.05-01 2 8371	0.00+00 2 8371	2.36+05 3 8391	1.02+05 3 8391	3.38+05 3	20
.00+00 2 8391	8.73+00 4 8382	6.54+01 4 8382	9.19+00 4 8382	1.41+00 4 8382	4.71+00 4 8382	3.27-01 4 8382	1.09+02 4	3.78+03 2 8383	3.45+00 3 8384	0999	0999	0999	2091	6.06-01 2 8381	0.00+00 2 8381	1.60+05 3 8390	8.36+04 3 8390	2.44+05 3	21
.00+00 2 8391	1.04+01 4 8352	1.00+02 4 8352	7.14+00 4 8352	1.67+00 4 8352	5.56+00 4 8352	3.41-01 4 8352	1.25+02 4	3.71+03 2 8353	3.54+00 3 8354	0999	0999	0999	2091	5.70-01 2 8351	0.00+00 2 8351	1.70+05 3 8387	7.00+04 3 8387	2.40+05 3	22
.00+00 2 8391	5.71+00 4 8357	6.83+01 4 8357	5.90+00 4 8357	1.15+00 4 8357	3.80+00 4 8357	3.13-01 4 8357	8.52+01 4	3.73+03 2 8358	3.75+00 3 8359	0999	0999	0999	2091	5.48-01 2 8356	0.00+00 2 8356	1.43+05 3 8388	5.96+04 3 8388	2.03+05 3	23
.00+00 2 8393	3.42+00 4 8367	5.83+01 4 8367	1.41+01 4 8367	9.28-01 4 8367	3.10+00 4 8367	3.01-01 4 8367	8.01+01 4	3.84+03 2 8368	4.54+00 3 8369	0999	0999	0999	2091	6.82-01 2 8366	0.00+00 2 8366	7.74+05 3 8386	1.06+05 3 8386	2.80+05 3	24
.00+00 2 8391	1.30+01 4 8362	1.15+02 4 8362	9.63+00 4 8362	1.71+00 4 8362	6.37+00 4 8362	3.54-01 4 8362	1.46+02 4	3.83+03 2 8363	3.96+00 3 8364	0999	0999	0999	2091	5.84-01 2 8361	0.00+00 2 8361	1.68+05 3 8389	9.88+04 3 8389	2.67+05 3	25
.00+00 2 8391	3.31+00 4 8377	3.81+01 4 8377	6.17+01 4 8377	5.95-01 4 8377	1.98+00 4 8377	4.37-01 4 8377	1.06+02 4	4.61+03 2 8378	3.16+00 3 8379	0999	0999	0999	2091	6.25-01 2 8376	0.00+00 2 8376	1.46+05 3 8392	9.55+04 3 8392	2.44+05 3	26
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.00+00 2 8312	2.85+00 4 8308	7.57+01 4 8308	2.12+01 4 8308	1.25+00 4 8308	4.17+00 4 8308	3.70-01 4 8308	1.05+02 4	4.50+03 2 8309	3.11+00 3 8310	0999	0999	0999	2091	5.73-01 2 8307	0.00+00 2 8307	2.13+05 3 8305	9.16+04 3 8305	3.05+05 3	30
.00+00 2 8312	9.56+00 4 8330	8.24+01 4 8330	3.17+01 4 8330	1.29+00 4 8330	4.41+00 4 8330	3.65-01 4 8330	1.29+02 4	5.20+03 2 8331	3.11+00 3 8332	0999	0999	0999	2091	6.07-01 2 8329	0.00+00 2 8329	1.77+05 3 8304	8.81+04 3 8304	2.65+05 3	31
.00+00 2 8312	1.27+01 4 8314	9.66+01 4 8314	3.28+01 4 8314	1.45+00 4 8314	5.08+00 4 8314	3.88-01 4 8314	1.49+02 4	5.14+03 2 8315	2.88+00 3 8316	0999	0999	0999	2091	5.88-01 2 8313	0.00+00 2 8313	1.90+05 3 8301	8.11+04 3 8301	2.71+05 3	32
.00+00 2 8312	5.27+00 4 8318	6.55+01 4 8318	2.97+01 4 8318	9.43-01 4 8318	3.16+00 4 8318	3.57-01 4 8318	1.05+02 4	5.16+03 2 8319	3.21+00 3 8320	0999	0999	0999	2091	6.04-01 2 8317	0.00+00 2 8317	1.61+05 3 8302	7.10+04 3 8302	2.32+05 3	33
.00+00 2 8312	3.99+00 4 8322	5.84+01 4 8322	3.77+01 4 8322	9.45-01 4 8322	3.16+00 4 8322	3.78-01 4 8322	1.05+02 4	5.26+03 2 8323	3.52+00 3 8324	0999	0999	0999	2091	6.70-01 2 8321	0.00+00 2 8321	1.89+05 3 8300	1.12+05 3 8300	3.01+05 3	34
.00+00 2 8312	1.46+01 4 8326	1.09+02 4 8326	2.67+01 4 8326	1.81+00 4 8326	6.04+00 4 8326	4.16-01 4 8326	1.58+02 4	5.24+03 2 8327	3.03+00 3 8328	0999	0999	0999	2091	5.66-01 2 8325	0.00+00 2 8325	1.66+05 3 8303	8.81+04 3 8303	2.54+05 3	35
.00+00 2 8312	3.31+00 4 8335	3.81+01 4 8335	6.17+01 4 8335	5.95-01 4 8335	1.98+00 4 8335	4.37-01 4 8335	1.06+02 4	4.61+03 2 8336	3.16+00 3 8337	0999	0999	0999	2091	6.25-01 2 8334	0.00+00 2 8334	1.46+05 3 8306	9.55+04 3 8306	2.44+05 3	36
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TABLE 2. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL HIGH BTU COAL GASIFICATION

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FOOTNOTES FOR TABLE 2

2091 Fire and/or explosions caused by gas leaks, oil leaks, act of God, or human error. Possible damage to refinery, personnel, adjacent properties.

8300 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Northern Appalachia, Central, and Northwest regions.

8301 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Northern Appalachia, Central, and Northwest regions.

8302 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Northern Appalachia, Central, and Northwest regions.

8303 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Northern Appalachia, Central, and Northwest regions.

8304 Capital and operating costs for this process are the arithmetic average of the National Average capital and operating costs for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8305 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Central and Northwest regions.

8306 Capital and operating costs for this process are identical to the capital and operating costs for the Northwest region.

8307 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Central and Northwest regions.

8308 Air pollutants for this process are the arithmetic average of the air pollutants for the Central and Northwest regions.

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8309 Solid waste for this process is the arithmetic average of the solid waste produced in the Central and Northwest regions

8310 Land utilized by this process is the arithmetic average of the land used in the Central and Northwest regions.

8311 Water pollutants for this process are the arithmetic average of the water pollutants for the Central and Northwest regions.

8312 Thermal discharges can be completely eliminated by the use of mechanical draft wet cooling towers.

8313 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Northern Appalachia, Central, and Northwest regions.

8314 Air pollutants for this process are the arithmetic average of the air pollutants for the Northern Appalachia, Central, and Northwest regions.

8315 Solid waste for this process is the arithmetic average of the solid waste produced in the Northern Appalachia, Central, and Northwest regions.

8316 Land utilized by this process is the arithmetic average of the land used in the Northern Appalachia, Central, and Northwest regions.

8317 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Northern Appalachia, Central, and Northwest regions.

8318 Air pollutants for this process are the arithmetic average of the air pollutants for the Northern Appalachia, Central, and Northwest regions.

8319 Solid waste for this process is the arithmetic average of the solid waste produced in the Northern Appalachia, Central, and Northwest regions.

8320 Land utilized by this process is the arithmetic average of the land used in the Northern Appalachia, Central, and Northwest regions.

8321 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Northern Appalachia, Central, and Northwest regions.

8322 Air pollutants for this process are the arithmetic average of the air pollutants for the Northern Appalachia, Central, and Northwest regions.

8323 Solid waste for this process is the arithmetic average of the solid waste produced in the Northern Appalachia, Central, and Northwest regions.

8324 Land utilized by this process is the arithmetic average of the land used in the Northern Appalachia, Central, and Northwest regions.

8325 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Northern Appalachia, Central, and Northwest regions.

8326 Air pollutants for this process are the arithmetic average of the air pollutants for the Northern Appalachia, Central, and Northwest regions.

8327 Solid waste for this process is the arithmetic average of the solid waste produced in the Northern Appalachia, Central, and Northwest regions.

8328 Land utilized by this process is the arithmetic average of the land used in the Northern Appalachia, Central, and Northwest regions.

8329 Primary efficiency and ancillary energy for this process are the arithmetic average of the National Average primary efficiencies and ancillary energies for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

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8330 Air pollutants for this process are the arithmetic average of the National Average air pollutants for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8331 Solid waste for this process is the arithmetic average of the solid wastes produced in the National Average case for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8332 Land utilized by this process is the arithmetic average of the land used in the National Average case by the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8333 Water pollutants for this process are the arithmetic average of the water pollutants for the Typical New Process in the Northern Appalachia, Central, and Northwest regions.

8334 The primary efficiency and ancillary energy for this process are the same as those for the Northwest region.

8335 Air pollutants for this process are the same as those for the Northwest region.

8336 Solid waste for this process is the same as that for the Northwest region.

8337 Land utilized by this process is the same as that used in the Northwest region.

8338 Water pollutants for this process are the same as those for the Northwest region.

8350 The Northwest coal used in this analysis has the following composition on a run-of-mine basis:

Proximate Analysis-Wt. Pc.		Ultimate Analysis-Wt. Pc.	
Ash	6.0	C	52.8
H_2O	22.0	H_2	3.6
Vol.Mat.	29.4	N_2	0.7
Fixed C.	42.6	O_2	14.4
		S	0.5
Btu/lb	8806	Ash	6.0
Sulfur	0.51	H_2O	22.0

For this coal 57000 ton is equivalent to 1.0E12 Btu.

8351 From (8300 and footnote 8350) for 253.3E09 Btu/D SNG, coal costs, based on $.15/1.0E06 Btu coal, are $.263/1.0E06 Btu gas. Thus 444.1E09 Btu coal/D is required to produce 253.3E09 Btu gas/D. The primary efficiency, taken as Btu of gas output/Btu of coal input, is therefore .570. From (8300), this size SNG plant also produces 4.84E04 GPD of light oils (primarily B-T-X) and 2.34E10 Btu/D of tars. If these fuels are considered, then the overall plant efficiency becomes .635. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8352 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	4.58	2.36	2.46	.738	44.3	.0123
Sulfur Recovery Plant		0.80				
Storage and Misc.				.001		.139

Fuels Combustion

Based on plant heat requirements similar to that in (8300), and the use of coal to supply the same proportionate share of this heat demand plus that due to the waste offgases from coal pretreatment (since pretreatment of western non-caking coals is not required), 1938 TPD of coal (6.0 percent ash, .51 percent S) are used for fuel, with the balance, 84E09 Btu/D, supplied by the combustion of gasifier char (30.3 percent ash,.5 percent S). These heating rates were converted to equivalent TPD of bituminous coal and used with (8301,1.1-3) to determine TPD of air emissions. Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

FTN. 8352 (Cont)

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery. From (2022,103) a three stage Claus plant operating on a 25 percent H_2S feed can recover 94 percent of the incoming S as elemental S. The incoming S for recovery is based on 23,279 TPD coal to the gasifier (footnote 8351, less the above 1938 TPD coal as fuel), .51 percent S in the coal, and 80 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the char). Based, furthermore, on complete recycle to the Claus plant of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 124.5 TPD S is the Claus feed. Thus 117.0 TPD of S are recovered or 264 ton S/1.0E12 Btu. 7.5 TPD of S passes to the Wellman Lord tailgas scrubbing unit, so that .4 TPD S or 0.8 TPD SO_2 passes out to the atmosphere from the Claus and tailgas treatment system.

Storage and Misc.

From (8300) 4.84E04 GPD of light oils (B-T-X) are produced. Assuming two weeks storage capacity under new tank conditions and emission factors from (8302, 4.3-8), .001 TPD HC are emitted. Based on 23,279 TPD coal to the gasifier, .007 ton N_2/ton coal, and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 139 TPD of NH_3 are produced in the gasifier. All of the NH_3 is washed from the gas synthesis stream and appears in the waste water. This waste water stream passes to an ammonia still with both a free and a fixed leg so that essentially all of the NH_3 is recovered for sale. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .139 TPD NH_3 are released to the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include,but are not limited to, coal and other solids preparation and and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8353 Based on 25,217 TPD coal with 6.0 percent ash, 1513 TPD ash are produced. Since 4.6 TPD is released to the atmosphere as particulate, 1508.4 TPD remains as solid waste for disposal. Based on 5500 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 16.5 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 1639.4 TPD (or 3705 ton/1.0E12 Btu).

8354 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operations which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 25,217 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.54 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8353 for solid waste).

8355 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8356 From (8300) and footnote 8350, for 247.2E09 Btu/D SNG, coal cost, based on $.15/1.0E06 Btu coal, is $.255/ 1.0E06 Btu gas. Thus 420.2E09 Btu coal/D is required to produce 247.2E09 Btu gas/D. The primary efficiency, taken as Btu of gas output/Btu of coal input, is therefore .588. From (8300) this size SNG plant also produces 4.56E04 GPD of light oils (primarily B-T-X) and 2.30E10 Btu/D of tars. If these fuels are considered, then the overall plant efficiency becomes .655. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8357 The principal quantifiable air pollutant sources are as follows:

TPD

	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	2.39	1.87	1.59	.480	28.6	.00797
Sulfur Recovery Plant		0.60				
Storage and Misc.				.001		.123

Fuels Combustion

Based on plant heat requirements similar to that in (8300), and the use of coal to supply the same proportionate share of this heat demand plus that due to the waste offgases from coal pretreatment (since pretreatment of western non-caking coals is not required), 3157 TPD of coal (6.0 percent ash, .51 percent S) are used for fuel, with the balance, 20.9E09 Btu/D, supplied by the combustion of gasifier char (52.6 percent ash, .9 percent S). These heating rates were converted to equivalent TPD of bituminous coal and used with (8301,1.1-3) to determine TPD of air emissions. Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery. From (2022,103) a three stage Claus plant operating on a 25 percent H_2S feed can recover 94 percent of the incoming S as elemental S. The incoming S for recovery is based on 20,704 TPD coal to the gasifier (footnote 8356, less the above 3157 TPD coal as fuel), .51 percent S in the coal, and 80 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the char). Based, furthermore, on complete recycle to the Claus plant of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 109.0 TPD S is the Claus feed. Thus 102.5 TPD of S are recovered or 245 ton S/1.0E12 Btu. 6.5 TPD S passes to the Wellman Lord tailgas scrubbing unit, so that .3 TPD S or 0.6 TPD SO_2 passes out to the atmosphere from the Claus and tailgas treatment system.

Storage and Misc.

From (8300) 4.56E04 GPD of light oils (B-T-X) are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Based on 20,704 TPD coal to the gasifier, .007 ton N_2/ton coal, and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 123 TPD of NH_3 are produced in the gasifier. All of the NH_3 is washed from the gas synthesis stream and appears in the waste water. This waste water stream passes to an ammonia still with both a free and a fixed leg so that substantially all of the NH_3 is recovered for sale. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .123 TPD NH_3 are released to the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8358 Based on 23,861 TPD coal with 6.0 percent ash, 1431.7 TPD ash are produced. Since 2.4 TPD is released to the atmosphere as particulate, 1429.3 TPD remains as solid waste for disposal. Based on 5300 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 15.9 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 1559.7 TPD or 3725 ton/1.0E12 Btu.

8359 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operation which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 23,861 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.75 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8358 for solid waste.)

8360 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8361 From (8300 and footnote 8350) for 231.8E09 Btu/D SNG, coal cost, based on $.15/1.0E06 Btu/coal, is $.257/1.0E06 Btu gas. Thus 397.2E09 Btu coal/D is required to produce 231.8E09 Btu gas/D. The primary efficiency, taken as Btu of gas output/Btu of coal input, is therefore .584. From (8300) this size SNG plant also produces 8.5E09 Btu/D of heavy oils, and from (8307,6) 25,000 GPD of B-T-X can be expected. If these fuels are considered, then the overall plant efficiency becomes .612. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generatdd on-site.

8362 The principal quantifiable air pollutant sources are as follows:

TPD

	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	5.15	1.61	2.52	.757	45.4	.0127
Sulfur Recovery Plant		2.20				
Storage and Misc.						.127

Fuels Combustion

Based on plant heat requirements similar to that in (8300), and the use of coal to supply the same proportionate share of this heat demand, 1170 TPD of coal (6.0 percent ash, .51 percent S) are used for fuel, with the balance, 100E09 Btu/D, supplied by the combustion of gasifier char (29.5 percent ash, .3 percent S). These heating rates were converted to equivalent TPD of bituminous coal and used with (8301,1.1-3) to determine TPD of air emissions. Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

FTN. 8362 (Cont)

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for the nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream is sent to the Claus plant for recovery. From (8303,AI-25) a Claus plant operating on this dilute feed can recover 84 percent of the incoming S as elemental S. The incoming S for recovery is based on 21,380 TPD coal to the gasifier (footnote 8361, less the above 1170 TPD coal as fuel), .51 percent S in the coal, and 90 percent of the S in the gasifier as H_2S to Claus for recovery (the balance of the S is in the char). Based, furthermore, on complete recycle to the Claus plant of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 133.6 TPD S is the Claus feed. Thus 112.2 TPD of S are recovered or 283 ton S/1.0E12 Btu. 21.4 TPD S passes to the Wellman Lord tailgas scrubbing unit, so that 1.1 TPD S or 2.2 TPD SO_2 passes out to the atmosphere from the Claus and tailgas treatment system.

Storage and Misc.

Based on 21,380 TPD coal to the gasifier, .007 ton N_2/ ton coal, and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 127 TPD of NH_3 are produced in the gasifier. All of the NH_3 is washed from the gas synthesis stream and appears in the waste water. This waste water stream passes to an ammonia still with both a free and a fixed leg so that substantially all of the NH_3 is recovered for sale. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .127 TPD NH_3 are released to the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8363 Based on 22,550 TPD coal with 6.0 percent ash, 1353 TPD ash are produced. Since 5.2 TPD is released to the atmosphere as particulate, 1347.8 TPD remains as solid waste for disposal. Based on 17700 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 53.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 1515.5 TPD or 3831 ton/1.0E12 Btu.

8364 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operations which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 22,550 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.96 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8363 for solid waste.)

8365 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8366 From (8300 and footnote 8350) for 236.1E09 Btu/D SNG, coal cost, based on \$.15/1.0E06 Btu coal, is \$.22/1.0E06 Btu gas. Thus 346.3E09 Btu coal/D is required to produce 236.1E09 Btu gas/D. The primary efficiency, taken as Btu of gas output/Btu of coal input, is therefore .682. No light or heavy oils are reported as byproducts for this process. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8367 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.18	3.05	1.07	.320	20.1	.00534
Sulfur Recovery Plant		1.80				
Storage and Misc.						.0985

Fuels Combustion

Based on plant heat requirements similar to those in (8305,63), a total of 3107 TPD of coal is required for fuel which includes 197 TPD for thermal drying of the coal. The 2910 TPD of subbituminous coal used as fuel in boilers is equivalent to 2135 TPD of bituminous coal and was used in conjunction with (8301,1.1-3) to determine boiler air emissions. Particulates were then reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit. Particulate emissions in compliance with the New Source Performance Standards for coal thermal dryers are limited to .03 grain/DSCF (1121). Based on 24000 DSCF/ton dry coal input to the dryer (1121) and 12,913 TPD dry coal to the dryer and gasifier, .664 TPD of particulates are emitted. Based on .535 lb NO_x/1.0E06 Btu coal fired (1121), .51 percent S coal, and 197 TPD coal for dryer fuel, .928 TPD NO_x and 2.01 TPD SO_2 are also released from the thermal dryer.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream is sent to the Claus plant for recovery. From (8303,AI-25) a Claus plant operating on this dilute feed can recover 84 percent of the incoming S as elemental S. The incoming S for recovery is based on 16,555 TPD coal to the gasifier (footnote 8366, less the above 3107 TPD coal as fuel), .51 percent S in the coal, and all of the S to the gasifier as H_2S to Claus for recovery (none in the slag). Based, furthermore, on complete recycle to the Claus plant of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 111.1 TPD is the Claus feed. Thus 93.3 TPD of S are recovered or 271 ton S/1.0E12 Btu. 17.8 TPD S passes to the Wellman Lord tailgas scrubbing unit, so that .9 TPD S or 1.8 TPD SO_2 passes out to the atmosphere from the Claus and tailgas treatment system.

Storage and Misc.

Based on 16,555 TPD coal to the gasifier, .007 ton N_2/ton coal, and 70 percent of the N_2 in the feed coal as NH_3(8303,X-7), 98.5 TPD of NH_3 are produced in the gasifier. All of the NH_3 is washed from the gas synthesis stream and appears in the waste water. This waste water stream passes to an ammonia still with both a free and a fixed leg so that substantially all of the NH_3 is recovered for sale. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .0985 TPD NH_3 are released to the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

FTN. 8368-8371

8368 Based on 19,662 TPD coal with 6.0 percent ash, 1179.7 TPD ash are produced. Since 1.2 TPD is released to the atmosphere as particulate, 1178.5 TPD remains as solid waste for disposal. Based on 10385 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 31.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 1324.2 TPD or 3839 ton/1.0E12 Btu.

8369 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operations which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 19,662 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 4.54 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8368 for solid waste.)

8370 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operations. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8371 From (8311,3.13) the total heat demand for a plant producing 252E09 Btu/D of SNG is 85.1E09 Btu/D and the TPD coal to the gasifier is 21860. This analysis is for a Southwestern Subbituminous coal with 62.0 percent volatile matter and fixed carbon and a heating value of 8310 Btu/lb. Based on footnote 8350 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Northwestern analysis would require 18824 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various subbituminous coal inputs, 4830 TPD coal is required for boiler fuel. Thus a total of 23654 TPD coal is required to produce 252E09 Btu/D SNG for a primary efficiency of .605. This size plant also produces 41.23E09 Btu/D of tars and tar oils and 63.6E03 GPD of naphtha (8311,3.13). If these fuels are considered, then the overall plant efficiency becomes .721. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8372 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	.851	1.72	1.77	.532	31.9	.00886
Sulfur Recovery Plant		0.60				
Storage and Misc.				.001		.112

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 3544 TPD of equivalent bituminous coal (4830 TPD of subbituminous coal). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 18824 TPD coal to the gasifier, .51 percent S in the coal, and 98 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the by-products) from (8310, sheet no. 00-1-02). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 117.1 TPD S is the Claus feed.

Thus 110.1 TPD S is recovered for sale or 265 ton S/1.0E12 Btu. Since 7 TPD S passes to the Wellman Lord tailgas scrubbing unit, .3 TPD S or .6 TPD SO_2 exits the stack.

Storage and Misc.

From (8311,3.13) 63.6E03 GPD of light oils are produced. Assuming two weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Based on 18824 TPD coal to the gasifier and .7 percent N_2 in the coal and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 112 TPD NH_3 is produced in the gasifier. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .112 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8373 Based on 23654 TPD coal with 6 percent ash, 1419 TPD ash are produced. Since 1 TPD is released to the atmosphere as particulate, 1418 TPD remains as solid waste for disposal. Based on 5100 GPM net makeup H_2O (8311,3.20) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 15.3 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. The sum total solid waste produced is thus 1548 TPD or 3731 ton/1.0E12 Btu.

8374 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operations which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 23654 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.78 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8373 for solid waste.)

8375 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8376 This process can be operated with only a lignite coal input. Thus the following lignite coal (ROM) was used in this analysis:

		Proximate Analysis - WT PC	
Btu/lb	7070	Ash	7.2
S-WT PC	0.6	H_2O	33.7
		Vol. Mat. and Fixed C.	59.1

For this coal 71000 ton of coal is equivalent to 1.0E12 Btu. From (8300) 25360 TPD coal is required for the gasifier and 2937 TPD for plant fuel to produce 250E09 Btu/D SNG. The primary efficiency is thus .625. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8377 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.32	10.0	.791	.237	15.2	.00395
Sulfur Recovery Plant		14.6				
Storage and Misc.						.170

Fuels Combustion

Based on the combustion of 1581 TPD bituminous coal (2683 TPD lignite) as plant fuel and air emissions factors from (8301,1.1-3). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub while SO_2 emissions were reduced 95 percent by the Wellman Lord unit. Also included are the emissions from combustion of 254 TPD of lignite to dry the gasifier feed coal. Based on .535 lb NO_x/1.0E06 Btu coal fired (1121) and .6 percent S coal, .961 TPD NO_x and 3.05 TPD SO_2 are emitted. Particulate emissions in compliance with the New Source Performace Standards for coal thermal dryers are limited to .03 grain/DSCF (1121). Based on 24000 DSCF/ton dry coal input to the dryer (1121) and 16814 TPD dry coal to the dryer and gasifier, .865 TPD particulates are emitted. Based, furthermore, on 2 percent of the S in the feed coal evolved as SO_2 (8321, 20), an additional 6.09 TPD SO_2 is released from the coal thermal dryer.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for the nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream is sent to the Claus plant for recovery. From (8303,AI-25) a Claus plant operating on this dilute feed can recover 84 percent of the incoming S as elemental S. The incoming S for recovery is based on 25360 TPD coal to the gasifier, .6 percent S in the coal, and 3 percent of the S as H_2S to Claus for recovery (3 percent of the S is in the ash and 92 percent of the S is evolved as SO_2 from the regenerator).

Based, furthermore, on 30 percent of the total S to Claus as SO_2 (8303,AI-27) from the Wellman Lord scrubbing units, 6.6 TPD S is the Claus feed. Thus 5.5 TPD S is recovered for sale or 13.8 ton S/1.0E12 Btu. Since 5.5 TPD S passes to the Wellman Lord tailgas scrubbing unit, .3 TPD S or .6 TPD SO_2 is emitted. The bulk of the S in the gasifier coal is released as SO_2 in the regenerator (92 percent). Based on a Wellman Lord unit to treat this stream (144 TPD S), 7 TPD S or 14 TPD SO_2 leaves with the regenerator offgases. The total recovered SO_2 for sale is 289.6 TPD SO_2 or 727 ton SO_2/1.0E12 Btu.

Storage and Misc.

Based on 16814 TPD MF lignite to the gasifier, 1.19 percent N_2 in MF lignite (8321,20), and 70 percent of the N_2 as NH_3 (8303,X-7) 170 TPD NH_3 are produced in the gasifier. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .170 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be persent in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8378 Based on 28297 TPD coal with 7.2 percent ash, 2037 TPD ash are produced. Since 1 TPD is released to the atmosphere as particulate, 2036 TPD remains as solid waste for disposal. Based on 6580 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 19.8 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. From (8321,20) it is estimated that 1260 TPD MgO-CaO will have to be discarded from the regeneration operation in this process. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 3431 TPD or 8610 ton/1.0E12 Btu.

FTN. 8379-8385

8379 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities, and an additional 165 acres for evaporation ponds (8306) to handle the following TDS streams - H_2O softener and demineralizer blowdowns, boiler and cooling tower blowdowns, and H_2O from ash quenching and transfer operation which might contain leachates. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 515 acres is required for a 28297 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.16 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8378 for solid waste.)

8380 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste water and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

8381 Primary efficiency and ancillary energy for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8382 Air pollutants for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8383 Solid waste production for this process is an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas,and Synthane processes.

8384 Land utilization by this process is an arithmetic average of those used by the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8385 Water pollutants for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8386 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-19,700 TPD, 90 P LF

From (8300), escalated at 5 percent from 1971 $, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, O_2 manufacture, steam and power plant, general utilities, and general offsites total 165.2E06 $. Water pollution control costs were estimated at 11.7E06 $ from (2013,VII-5), (8304), and (8315). Sulfur recovery costs were estimated at 5.0 E06 $ from (8300) and (8303,AI-25,AI-26). Capital cost was reduced by 20E06 $ to reflect savings for a noncaking low S western coal. To the subtotal were added a 15 percent project contingency and a 7 percent development contingency to give a total plant investment of 197.5E06 $. Based on a FCR of 10 percent/yr and 6.46E06 TPY coal, this is equivalent to 1.74E05 $/ 1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-19,700 TPD, 90 P LF

From (8300) directly, catalysts and chemicals, purchased raw H_2O, and process operating labor total $.0405/1.0E06 Btu gas. Maintenance labor, supervision labor, administration and general overhead, operating and maintenance supplies are from (8303,AI-5). The total gross operating cost is thus $.1694/1.0E06 Btu gas or 13.12E06 $/yr for a 236.1E09 Btu/D SNG plant. By-products are credited at $10/LTS (83 LTS/D) and $25/T NH_3 (98 TPD NH_3) from (8303,AI-5). The total net operating cost is 12.04E06 $/yr or, for 6.46E06 TPY coal, 1.06E05 $/1.0E12 Btu.

8387 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-25,200 TPD, 90 P LF

From (8300), escalated at 5 percent from 1971 $, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, steam and power plant, general utilities, and general offsites total 200.9E06 $. Water pollution control costs were estimated at 11.7E06 $ from (2013,VII-5), (8304), and (8315). Sulfur recovery costs were estimated at 10E06 $ from (8300) and (8303,AI-25,AI-26). Capital cost was reduced by 20E06 $ to reflect savings for a noncaking low S western coal. To the subtotal were added a 15 percent project contingency and a 7 percent development contingency to give a total plant investment of 247.2E06 \$. Based on 10 percent/yr FCR and 8.28E06 TPY coal, this becomes 1.70E05 \$/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-25,200 TPD, 90 P LF

From (8300) directly, other raw material, catalysts and chemicals, purchased raw H_2O, and process operating labor total \$.0438/1.0E06 Btu gas. Maintenance labor, supervision labor, administration and general overhead, operating and maintenance supplies are from (8303,AI-5). The total gross operating cost is \$.1966/1.0E06 Btu gas for a 253.3E09 Btu/D SNG plant. By-products are credited at \$10/LTS (105 LTS/D), \$25/T NH_3 (139 TPD NH_3), \$.15/gal B-T-X (48.4E03 GPD)and \$.30/1.0E06 Btu tars (23.4E09 Btu/D) from (8303,AI-5). The total net operating cost is \$10.15E06/yr or, for 8.28E06 TPY coal, 7.00E04 \$/1.0E12 Btu.

8388 Capital and operating costs were developed as follows:

Capital Costs-1972 \$-Plant Basis-23,900 TPD, 90 P LF

From (8300), escalated at 5 percent from 1971 \$, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, O_2 manufacture, steam and power plant, general utilities, and general offsites total 160E06 \$. Water pollution control costs were estimated at 11.7E06 \$ from (2013,VII-5), (8304), and (8315). Sulfur recovery costs were estimated at 9.2E06 \$ from (8300) and (8303,AI-25,AI-26). Capital cost was reduced by 20E06 \$ to reflect savings for a noncaking low S western coal. To the subtotal were added a 15 percent project contingency and a 7 percent development contingency to give a total plant investment of 196.3E06 \$. Based on 10 percent/yr FCR and 7.84E06 TPY coal, this becomes 1.43E05 \$/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-23,900 TPD, 90 P LF

From (8300) directly, other raw material, catalysts and chemicals, purchased raw H_2O, and process operating labor total \$.0432/1.0E06 Btu gas. Maintenance labor, supervision labor, administration and general overhead, operating and maintenance supplies are from (8303,AI-5). The total gross operating cost is \$.1728/1.0E06 Btu gas for a 247.2E09 Btu/D SNG plant. By-products are credited at \$10/LTS (91 LTS/D), \$25/T NH_3 (123 TPD NH_3),\$.15/gal B-T-X (45.6E03 GPD)and \$.30/1.0E06 Btu tars (23E09 Btu/D) from (8303,AI-5). The total net operating cost is \$8.19E06/yr or, for 7.84E06 TPY coal, 5.96E04 \$/1.0E12 Btu.

8389 Capital and operating costs were developed as follows:

Capital Costs-1972 \$-Plant Basis-22,600 TPD, 90 P LF

From (8300), escalated at 5 percent from 1971 \$, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, compression, O_2 manufacture, steam and power plant, general utilities, and general offsites total 180.7E06 \$. Water pollution control costs were estimated at 11.7E06 \$ from (2013,VII-5), (8304), and (8315). Sulfur recovery costs were estimated at 6E06 \$ from (8300) and (8303,AI-25,AI-26). Capital cost was reduced by 20E06 \$ to reflect savings for a noncaking low S western coal. To the subtotal were added a 15 percent project contingency and a 7 percent developement contingency to give a total plant investment of 217.7E06 \$. Based on 10 percent/yr FCR and 7.41E06 TPY coal, this becomes 1.68E05 \$/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-22,600 TPD, 90 P LF

From (8300) directly, catalysts and chemicals, purchased raw H_2O, and process operating labor total \$.066/1.0E06 Btu gas. Maintenance labor, supervision labor, administration and general overhead, operating and maintenance supplies are from (8303,AI-5). The total gross operating cost is \$.2152/1.0E06 Btu gas for a 231.8E09 Btu/D SNG plant. By-products are credited at \$10/LTS (100 LTS/D), \$25/T NH_3 (127 TPD NH_3), \$.15/gal B-T-X (25000 GPD), and \$.30/1.0E06 Btu tars (8.5E09 Btu/D) from (8303, AI-5). The total net operating cost is \$12.83E06/yr or, for 7.41E06 TPY coal, 9.88E04 \$/1.0E12 Btu.

8390 Capital and operating costs for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8391 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-23,700 TPD, 90 P LF

From (8319,exhibit K page 2) costs for process units, utility units, offsite units, water pipeline, catalysts and lubricants, general plant, engineering fees and licenses, contingency, and start up total 321.4E06 $. Based on 10 percent/yr FCR and 7.77E06 TPY coal, this becomes 2.36E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-23,700 TPD, 90 P LF

From (8319,exhibit N,Schedule 3) the average operating and maintenance expenses for the first three years of operation include costs for operation supervision and engineering, other power expenses, other process production expenses, rents, maintenance supervision and engineering, maintenance of structures and improvements, maintenance of production equipment, administrative and general (less property insurance). The total gross operating cost is $22.32E06/yr. By-products are credited at $10/LTS (98 LTS/D), $25/T NH_3 (112 TPD), $.15/gal B-T-X (63.6E03 GPD)and $.30/1.0E06 Btu tars (41.2E09 Btu/D) from (8303,AI-5). The total net operating cost is $13.88E06/yr or, for 7.77E06 TPY coal, 1.02E05 $/1.0E12 Btu.

8392 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-28,300 TPD, 90 P LF

From (8300), escalated at 5 percent from 1971 $, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, compression, sulfur recovery, general utilities, and general offsites total 135E06 $. Steam and power plant costs are from (8300) with $200/KW added for on-site generation of 2180 KW previously purchased. Water pollution control costs were estimated at 11.7E06 $ from (2013,VII-5), (8304), and (8315). To the subtotal were added a 15 percent project contingency and a 7 percent development contingency to give a total plant investment of 193.3E06 $. Based on 10 percent/yr FCR and 9.30E06 TPY coal, this becomes 1.48E05 $/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-28,300 TPD, 90 P LF

From (8300) directly, catalysts and chemicals, purchased raw H_2O, and process operating labor total \$.062/1.0E06 Btu gas. Maintenance labor, supervision labor, administration and general overhead, operating and maintenance supplies are from (8303,AI-5). The total gross operating cost is \$.1808/1.0E06 Btu gas for a 250E09 Btu/D SNG plant. By-products are credited at \$10/LTS (12 LTS/D), \$4/LT SO_2 (649 LT SO_2/D), and \$25/T NH_3 (170 TPD) from (8303,AI-5). The total net operating cost is \$12.51E06/yr or,for 9.3E06 TPY coal, 9.55E04 \$/1.0E12 Btu.

8393 Thermal discharges can be completely eliminated by the use of mechanical draft wet cooling towers.

8400 The Northern Appalachia coal used in this study has the following composition on a run-of-mine basis:

		Proximate Analysis - WT PC	
Btu/lb	12197	Ash	15.1
S-WT PC	1.3	Water	2.5
		Vol.Mat.	30.9
		Fixed C.	51.5

For this coal 41,000 ton of coal is equivalent to 1.0E12 Btu.

8401 From (8300) the total heat demand for a plant producing 253.3E09 Btu/D SNG is 113E09 Btu/D and the TPD coal to the gasifier is 16754. This analysis is for an Eastern Bituminous coal with 83.4 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8400 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Northern Appalachia analysis would require 16953 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 1197 TPD coal is required for boiler fuel. Thus a total of 18150 TPD coal is required to produce 253.3E09 Btu/D SNG for a primary efficiency of .572. This size plant also produces 9.84E09 Btu/D of tars and 52.5E03 GPD of light oils (8300).

If these fuels are considered, then the overall plant efficiency becomes .608. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8402 The principal quantifiable air pollutant sources are as follows:

TPD

	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	6.20	9.30	2.04	.564	40.0	.00919
Sulfur Recovery Plant		1.00				
Storage and Misc.				.001		.165

Fuels Combustion

Based on air emission factors in (8301,1.1-3,1.4-2) and the combustion of 2478 TPD of coal equivalent char (55 percent ash, 1 percent S), 1197 TPD coal (15 percent ash, 1.3 percent S), and 24.3E09 Btu/D waste offgases (containing 25 percent of the total S in the coal to the gasifier). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 16953 TPD coal to the gasifier, 1.3 percent S in the coal, and 55 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the pretreatment offgases and the char) from (8303,X-13,and 8303,27). Based, furthermore, on 30 percent of total S to Claus as SO_2 (8303,AI-27) from the Wellman Lord scrubbing units, 173 TPD S is the Claus feed. Thus 163 TPD S is recovered along with an additional (to that which the Claus can accept) 93.6 TPD SO_2 for sale. These are equivalent to 368 ton S and 211 ton SO_2/1.0E12 Btu. Since 10 TPD S passes to the Wellman Lord tailgas scrubbing unit, .5 TPD S or 1.0 TPD SO_2 exits the stack.

Storage and Misc.

From (8300) 5.25E04 GPD of light oils are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Based on 16754 TPD coal to the gasifier and 1.16 percent N_2 in the coal (8300) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 165 TPD NH_3 is produced in the gasifier. This value was used for this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .165 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commerical coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8403 Based on 18150 TPD coal with 15.1 percent ash, 2741 TPD ash are produced. Since 6.2 TPD is released to the atmosphere as particulate, 2735 TPD remains as solid waste for disposal. Based on 6500 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 19.5 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2869 TPD or 6480 ton/1.0E12 Btu.

8404 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 18,150 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.41 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8403 for solid waste.)

8405 From (8300) the total heat demand for a plant producing 247.2E09 Btu/D of SNG is 73.4E09 Btu/D and the TPD coal to the gasifier is 14957. This analysis is for an Eastern Bituminous coal with 83.4 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8400 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Northern Appalachia analysis would require 15135 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 2124 TPD coal is required for boiler fuel. Thus a total of 17259 TPD coal is required to produce 247.2E09 Btu/D SNG for a primary efficiency of .587. This size plant also produces 8.84E09 Btu/D of tars and 46E03 GPD of light oils (8300). If these fuels are considered, then the overall plant efficiency becomes .620. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8406 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.28	7.55	1.23	.329	25.3	.00531
Sulfur Recovery Plant		1.00				
Storage and Misc.				.001		.148

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 2124 TPD coal (15 percent ash, 1.3 percent S) and 21.6E09 Btu/D waste offgases (containing 25 percent of the total S in the coal to the gasifier). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 15135 TPD coal to the gasifier, 1.3 percent S in the coal, and 55 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the pretreatment offgases and the char) from (8303,X-13, and 8303,27). Based, furthermore, on 30 percent of total S to Claus as SO_2 (8303,AI-27) from the Wellman Lord scrubbing units, 155 TPD S is the Claus feed. Thus 145 TPD S is recovered along with an additional (to that which the Claus can accept) 68.2 TPD SO_2 for sale. These are equivalent to 345 ton S and 162 ton SO_2/1.0E12 Btu. Since 9.3 TPD S passes to the Wellman Lord tailgas scrubbing unit, .5 TPD S or 1.0 TPD SO_2 exits the stack.

Storage and Misc.

From (8300) 4.63E04 GPD of light oils are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8),.001 TPD HC are emitted. Based on 14957 TPD coal to the gasifier and 1.16 percent N_2 in the coal (8300) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 148 TPD NH_3 is produced in the gasifier. This value was used for this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .148 TPD NH_3 are released to the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8407 Based on 17259 TPD coal with 15.1 percent ash, 2606 TPD ash are produced. Since 1.3 TPD is released to the atmosphere as particulate, 2605 TPD remains as solid waste for disposal. Based on 4600 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 13.8 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2733 TPD or 6492 ton/1.0E12 Btu.

8408 Land requirements are assumed to be 350 acres from (9401,7) fo coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 17,259 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.53 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8407 for solid waste.)

8409 From (8300) and (8309) the total heat demand for a plant producing 231.8E09 Btu/D of SNG is 116.3E09 Btu/D and the TPD coal to the gasifier is 14594. This analysis is for an Eastern Bituminous coal with 86.9 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8400 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Northern Appalachia analysis would require 15391 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 2358 TPD coal is required for boiler fuel. Thus a total of 17749 TPD coal is required to produce 231.8E09 Btu/D SNG for a primary efficiency of .535. This size plant also produces 13.9E09 Btu/D of tars (8300) and 25000 GPD of light oils (8307,6). If these fuels are considered, then the overall plant efficiency becomes .575. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8410 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	6.66	4.08	2.40	.721	43.2	.0120
Sulfur Recovery Plant		4.00				
Storage and Misc.						.402

Fuels Combustion

Based on air emissions factors in (8301,1.1-3) and the combustion of 2448 TPD of coal equivalent char (53.5 percent ash, .5 percent S) and 2358 TPD coal (15 percent ash, 1.3 percent S). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream can be sent to the Claus plant for recovery, and from (8303,AI-25) this Claus unit can recover 84 percent of the incoming S. The incoming S for recovery is based on 15391 TPD coal to the gasifier, 1.3 percent S in the coal, and 87 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the char (10 percent) and tar (3 percent)) from (8307,9). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 251 TPD S is the Claus feed. Thus 211 TPD S is recovered for sale or 487 ton S/1.0E12 Btu. Since 40.1 TPD S passes to the Wellman Lord tailgas scrubbing unit, 2.0 TPD S or 4.0 TPD SO_2 exits the stack.

Storage and Misc.

Based on 14594 TPD coal to the gasifier and 1.4 percent N_2 in the coal (8300) and (8309) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 174 TPD NH_3 is produced in the gasifier. This value was used for this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .174 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8411 Based on 17749 TPD coal with 15.1 percent ash, 2680 TPD ash are produced. Since 6.7 TPD is released to the atmosphere as particulate, 2673 TPD remains as solid waste for disposal. Based on 17700 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 53.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 ton/D of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2841 TPD or 6563 ton/1.0E12 Btu.

8412 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 17,749 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.46 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8411 for solid waste.)

8413 From (8305,63) the total heat demand for a plant producing 235.8E09 Btu/D of SNG is 2299 TPD coal and the TPD coal to the gasifier is 12224. This analysis is for a West Kentucky seam coal with a 84.9 percent volatile matter and fixed carbon,and a heating value of 12330 Btu/lb. Based on footnote 8400 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile matter and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Northern Appalachia analysis would require 12595 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 2179 TPD coal is required for boiler fuel (with no coal drying). Thus a total of 14774 TPD coal is required to produce 235.8E09 Btu/D SNG for a primary efficiency of .654. No light or heavy oils are reported as by-products for this process. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8414 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.32	2.69	1.09	.327	19.6	.00545
Sulfur Recovery Plant		3.60				
Storage and Misc.						.142

Fuels Combustion

Based on air emissions factors in (8301,1.1-3) and the combustion of 2179 TPD of coal (15.1 percent ash, 1.3 percent S). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream can be sent to the Claus plant for recovery, and from (8303,AI-25) this Claus unit can recover 84 percent of the incoming S. The incoming S for recovery is based on 12595 TPD coal to the gasifier, 1.3 percent S in the coal, and all of the S to the gasifier as H_2S to Claus for recovery from (8305,61). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 223 TPD S is in the Claus feed. Thus 187 TPD S is recovered for sale,or 520 ton S/1.0E12 Btu. Since 36 TPD S passes to the Wellman Lord tailgas scrubbing unit, 1.8 TPD S or 3.6 TPD SO_2 exits the stack.

Storage and Misc.

Based on 12224 TPD coal to the gasifier and 1.37 percent N_2 in the coal (8305,60,63) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 142 TPD NH_3 is produced in the gasifier. This value was used for this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit two lb of NH_3/ton NH_3. Thus .142 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8415 Based on 14774 TPD coal with 15.1 percent ash, 2231 TPD ash are produced. Since 1.3 TPD is released to the atmosphere as particulate, 2230 TPD remains as solid waste for disposal. Based on 10385 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 31.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2375 TPD or 6592 ton/1.0E12 Btu.

8416 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 14774 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.96 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8415 for solid waste.)

8417 Primary efficiency and ancillary energy for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8418 Air pollutants for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8419 Solid waste production for this process is an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8420 Land utilization by this process is an arithmetic average of those used by the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

FTN. 8421

8421 Water pollutants are based on the following process waste water analysis:

Contaminant	Waste Water-PPM	Reference	Effluent-PPM
Phenols	1700	(8307,4)	0.006
Cyanide	0.6	(8307,4)	0.3
Thiocyanates	188	(8307,4)	0.0
NH_3	17040	Calculated	17.0
Sulfide	1400	(8307,4)	0.01
Oil	1100	(8303,X-3)	3.7
Sus.Solids	600	(8307,4)	4.3

The following waste water treatment system was utilized to achieve the above effluent values - 3 stages of oil-water separation, dissolved air flotation, free and fixed ammonia stills, equalization, activated sludge and clarification, and char polishing tower. Three stages of oil-water separation were used to insure complete separation of the tars and process waste water (8310,III-08-1). An air flotation unit was used to further remove oil and suspended solids (8311,3.21). Based on coke plant experience (1119), (8312),and (8313,618), ammonia removal appears to be the key to treatment of weak ammonia liquor. Since the above process waste water is very similar to WAL, a free and fixed ammonia still operation was employed. Phenol biodegradation in an activated sludge unit has been successfully demonstrated on coke plant WAL (8312,202). Complete thiocyanate removal is possible by biodegradation of WAL that has previously been deammoniated (8313,618). TPD emissions are based on 1 ton H_2O/ton coal to the gasifier for a Typical New Process (15370 TPD) and 60 percent of this H_2O as process waste water condensate (9220 TPD) from (8314). Other dissolved solids TPD emissions are based on a Typical New Process makeup H_2O requirement of 9800 GPM (8300), an assumed influent TDS loading of 500 PPM, and a contribution of other dissolved solids by the gasification facility of 50 percent of the incoming TDS (similar to refinery operations (8317,8) and also from (1900)). These ODS are contributed by ion exchange regenerants, treating chemicals, corrosion and scale inhibitors, etc. Organics comprise phenols and oil, while total dissolved solids includes cyanide, thiocyanates, NH_3, sulfide, and other dissolved solids. Waste water system removal efficiencies were developed from (2013,IV-3), (8316,172) (8318,Table 7) and (8313, 609,618). Tons/1.0E12 Btu based on an average plant input of 16980 TPD coal.

8422 Capital and operating costs were developed as follows:

Capital costs-1972 $-Plant Basis-14,800 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for the feed system, gasification and CO shift, methanation, O_2 manufacture, steam and power plant, general utilities, and general offsites total 119.2E06 $. From (8305), escalated at 5 percent/year from 1970 to 1972 $, costs for coal storage and preparation and gas purification total 44.3E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 8.7E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 224.4E06 $. Based on a FCR of 10 percent/year and 4.85E06 TPY coal this is equivalent to 1.89E05 $/ 1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-14,800 TPD, 90 P LF

From (8300) the following costs were taken directly-other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.053/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/year of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/year of total plant investment. The total gross operating cost is thus $.1995/ 1.0E06 Btu gas or 15.40E06 $/yr for a 235.8E09 Btu/D SNG plant. By-products are credited at $10/LT for S (167.3 LTS/D) and $25/T NH_3 (142.3 TPD NH_3) from (8303,AI-5). The total net operating cost is therefore $13.68E06/yr or,for a 4.85E06 TPY coal input, 1.15E05 $/1.0E12 Btu.

8423 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-18,200 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal storage and preparation, pretreatment, feed system, gasification and CO shift, methanation, steam and power plant, general utilities, and general offsites total 175.6E06 $. From (8300) cost for gas purification is estimated at 22.9E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 13.8E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 273.3E06 $. Based on a FCR of 10 percent/yr and 5.96E06 TPY coal this is equivalent to 1.88E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-18,200 TPD, 90 P LF

From (8300) the following costs were taken directly-other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.048/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus $.2155/1.0E06 Btu gas or 17.90E06 $/yr for a 253.3E09 Btu/D SNG plant. By-products are credited at $10/LT for S (145.3 LTS/D), $4/LT for SO_2 (83.6 LT SO_2/D), $25/T NH_3 (165 TPD NH_3), $.15/gal for B-T-X (52.5E03 GPD)and $.30/1.0E06 Btu for tars (9.84E09 Btu/D) from (8303,AI-5). The total net operating cost is therefore $12.40E06/yr or, for a 5.96E06 TPY coal input, 8.54E04 $/1.0E12 Btu.

8424 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-17,300 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent,costs for coal storage and preparation, pretreatment, feed system, gasification and CO shift, methanation, oxygen manufacture, steam and power plant, general utilities, and general offsites total 132.4E06 $. From (8300) cost for gas purification is estimated at 22.9E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 13.1E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 219.7E06 $. Based on a FCR of 10 percent/yr and 5.67E06 TPY coal this is equivalent to 1.59E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-17,300 TPD, 90 P LF

From (8300) the following costs were taken directly-other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.046/1.0E06 Btu/gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus $.1886/1.0E06 Btu gas or 15.30E06 $/yr for a 247.2E09 Btu/D SNG plant. By-products were credited at $10/LT for S (129.7 LTS/D), $4/LT for SO_2 (60.9 LT SO_2/D), $25/T NH_3 (147.5 TPD NH_3), $.15/gal for B-T-X (46E03 GPD), and $.30/1.0E06 Btu for tars (8.84E09 Btu/D) from (8303,AI-5).The total net operating cost is therefore $10.43E06/yr or, for a 5.67 E06 TPY coal input, 7.55E04 $/1.0E12 Btu.

8425 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-17,700 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation, compression, oxygen manufacture, steam and power plant, general utilities, and general offsites total 153.8E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 14.9E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 220.1E06 $. Based on a FCR of 10 percent/yr and 5.83E06 TPY coal this is equivalent to 1.55E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-17,700 TPD, 90 P LF

From (8300) the following costs were taken directly - catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.064/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/year of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/year of total plant investment. The total gross operating cost is thus $.2148/1.0E06 Btu gas or 16.32E06 $/yr for a 231.8E09 Btu/D SNG plant. By-products were credited at $10/LT for S (187.5 LTS/D), $25/T NH_3 (173.6 TPD NH_3), $.15/gal for B-T-X (25000 GPD), and $.30/1.0E06 Btu for tars (13.9E09 Btu/D) from (8303,AI-5). The total net operating cost is therefore $11.62E06/yr or, for a 5.83E06 TPY coal input, 8.18E04 $/1.0E12 Btu.

8426 Capital and operating costs for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8427 Thermal discharges can be completely eliminated by the use of mechanical draft wet cooling towers.

8450 The Central coal used in this study has the following composition on a run-of-mine basis:

		Proximate Analysis-WT PC	
Btu/lb	11364	Ash	11.2
S-WT PC	3.5	Water	8.3
		Vol.Mat.	37.5
		Fixed C.	43.0

For this coal 44000 ton of coal is equivalent to 1.0E12 Btu.

8451 From (8300) the total heat demand for a plant producing 253.3E09 Btu/D of SNG is 113E09 Btu/D and the TPD coal to the gasifier is 16754. This analysis is for an Eastern Bituminous coal with 83.4 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8450 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Central analysis would require 17353 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 553 TPD coal is required for boiler fuel. Thus a total of 17906 TPD coal is required to produce 253.3E09 Btu/D SNG for a primary efficiency of .622. This size plant also produces 9.84E09 Btu/D of tars and 52.5E03 GPD of light oils (8300). If these fuels are considered, then the overall plant efficiency is .662. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

FTN. 8452

8452 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	5.59	24.9	2.06	.571	40.4	.00931
Sulfur Recovery Plant		2.8				
Storage and Misc.						.165

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 3171 TPD of coal equivalent char (42 percent ash,2.6 percent S), 553 TPD coal (11.2 percent ash,3.5 percent S), and 24.3E09 Btu/D waste offgases (containing 25 percent of the total S in the coal to the gasifier). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 17353 TPD coal to the gasifier, 3.5 percent S in the coal, and 55 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the pretreatment offgases and the char) from (8303,X-13, and 8308,27). Based, furthermore, on 30 percent of total S to Claus as SO_2 (8303,AI-27) from the Wellman Lord scrubbing units, 477 TPD S is the Claus feed. Thus 448 TPD S is recovered along with an additional (to that which the Claus can accept) 242 TPD SO_2 for sale. These are equivalent to 1101 ton S and 594 ton SO_2/1.0E12 Btu. Since 29 TPD S passes to Wellman Lord tailgas scrubbing unit, 1.4 TPD S or 2.8 TPD SO_2 exits the stack.

Storage and Misc.

Based on 16754 TPD coal to the gasifier and 1.16 percent N_2 in the coal (8300) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 165 TPD NH_3 is produced in the gasifier. This value was used for this analysis. Substantially all of the NH_3 is recovered in a free and fixed NH_3 still. From (8301,5.2-2) controlled storage and loading operations emit two lb NH_3/ton NH_3. Thus .165 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8453 Based on 17906 TPD coal with 11.2 percent ash, 2005 TPD ash are produced. Since 6 TPD is released to the atmosphere as particulate, 1999 TPD remains as solid waste for disposal. Based on 6500 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 19.5 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2133 TPD or 5242 ton/1.0E12 Btu.

8454 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 17906 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.62 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8453 for solid waste.)

8455 From (8300) the total heat demand for a plant producing 247.2E09 Btu/D of SNG is 73E09 Btu/D and the TPD coal to the gasifier is 14957. This analysis is for an Eastern Bituminous coal with 83.4 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8450 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Central analysis would require 15492 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 1575 TPD coal is required for boiler fuel. Thus a total of 17067 TPD coal is required to produce 247.2E09 Btu/D SNG for a primary efficiency of .637. This size plant also produces 8.84E09 Btu/D of tars and 46.3E03 GPD of light oils(8300),If these fuels are considered, then the overall plant efficiency is .673. The ancillary energy is zero because the plant is self-sustaining with all power and steam generated on-site.

8456 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	2.67	21.8	1.30	.346	26.4	.00561
Sulfur Recovery Plant		2.6				
Storage and Misc.				.001		.148

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 668 TPD of coal equivalent char (73 percent ash, 4.6 percent S), 1575 TPD coal (11.2 percent ash, 3.5 percent S), and 21.6E09 Btu/D waste offgases (containing 25 percent of the total S in the coal to the gasifier). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emission were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to Claus for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 15492 TPD coal to the gasifier, 3.5 percent S coal, and 55 percent of the S as H_2S to Claus for recovery (the balance of the S is in the pretreatment offgases and the char) from (8303,X-13, and 8308,27). Based, furthermore, on 30 percent of total S to Claus as SO_2 (8303,AI-27) from the Wellman Lord scrubbing units, 426 TPD S is the Claus feed. Thus 400 TPD S is recovered along with an additional (to that which the Claus can accept) 207 TPD SO_2 for sale. These are equivalent to 1031 ton S and 533 ton SO_2/1.0E12 Btu. Since 26 TPD S passes to the Wellman Lord tailgas scrubbing unit, 1.3 TPD S or 2.6 TPD SO_2 exits the stack.

Storage and Misc.

From (8300) 4.63E04 GPD of light oils are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Based on 14957 TPD coal to the gasifier and 1.16 percent N_2 in the coal (8300) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 148 TPD NH_3 is produced in the gasifier. This value was used for this analysis. Substantially all of this NH_3 is recovered in a free and fixed NH_3 still. From (8301, 5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3 . Thus .148 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8457 Based on 17067 TPD coal with 11.2 percent ash, 1912 TPD ash are produced. Since 3 TPD is released to the atmosphere as particulate, 1909 TPD remains as solid waste for disposal. Based on 4600 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 13.8 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all biotreating sludges are used as boiler fuel. The sum total solid waste produced is thus 2038 TPD or 5253 ton/1.0E12 Btu.

8458 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 17067 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.75 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8457 for solid waste.)

8459 From (8300) and (8309) the total heat demand for a plant producing 231.8E09 Btu/D of SNG is 116.3E09 Btu/D and the TPD coal to the gasifier is 14594. This analysis is for an Eastern Bituminous coal with 86.9 percent volatile matter and fixed carbon and a heating value of 12400 Btu/lb. Based on footnote 8450 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Central analysis would require 15754 TPD coal to the gasifier. Based on the assumption that the plant heat demand is relatively constant for the various bituminous coal inputs, 1831 TPD coal is required for boiler fuel. Thus a total of 17585 TPD coal is required to produce 231.8E09 Btu/D SNG for a primary efficiency of .580. This size plant also produces 13.9E09 Btu/D of tars (8300) and 25000 GPD of light oils (8307,6). If these fuels are considered, then the overall plant efficiency becomes .621. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8460 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	5.87	9.93	2.48	.742	44.5	.0124
Sulfur Recovery Plant		10.8				
Storage and Misc.						.174

Fuels Combustion

Based on air emissions factors in (8301,1.1-3) and the combustion of 3110 TPD coal equivalent char (40.6 percent ash, 1.3 percent S) and 1831 TPD coal (11.2 percent ash,3.5 percent S). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for nonselective removal of H_2S and $CO_2$from the synthesis gas stream, a dilute (5 percent) H_2S gas stream can be sent to the Claus plant for recovery, and from (8303,AI-25) this Claus unit can recover 84 percent of the incoming S. The incoming S for recovery is based on 15754 TPD coal to the gasifier, 3.5 percent S in the coal, and 87 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the char (10 percent) and tar (3 percent)) from (8307,9). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 676 TPD S is the Claus feed. Thus 568 TPD S is recovered for sale,or 1421 ton S/1.0E12 Btu. Since 108 TPD S passes to the Wellman Lord tailgas scrubbing unit, 5.4 TPD S or 10.8 TPD SO_2 exits the stack.

Storage and Misc.

Based on 14594 TPD coal to the gasifier and 1.4 percent N_2 in the coal (8300) and (8309) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 174 TPD NH_3 is produced in the gasifier. This value was used for this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .174 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8461 Based on 17585 TPD coal with 11.2 percent ash, 1970 TPD ash are produced. Since 6 TPD is released into the atmosphere as particulate, 1964 TPD remains as solid waste for disposal. Based on 17700 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 53.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2132 TPD or 5334 ton/1.0E12 Btu.

8462 Land requirements are assumed to be 350 acres from (9401, 7) f coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 17585 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.67 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8461 for solid waste.)

8463 From (8305,63) the total heat demand for a plant producing 235.8E09 Btu/D of SNG is 2299 TPD coal and the TPD coal to the gasifier is 12224. This analysis is for a West Kentucky seam coal with 84.9 percent volatile matter and fixed carbon and a heating value of 12330 Btu/lb. Based on footnote 8450 and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Central analysis would require 12892 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 2338 TPD coal is required for boiler fuel and 156 TPD is needed for coal drying. Thus a total of 15386 TPD coal is required to produce 235.8E 09 Btu/D SNG for a primary efficiency of .674. No light or heavy oils are reported as by-products for this process. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8464 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.66	18.7	1.17	.351	21.9	.00585
Sulfur Recovery Plant		9.8				
Storage and Misc.						.142

Fuels Combustion

Based on air emissions factors in (8301,1.1-3) and the combustion of 2338 TPD coal (11.2 percent ash, 3.5 percent S). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit. Particulate emissions in compliance with the New Source Performance Standards for coal thermal dryers are limted to .03 grain/DSCF (1121). Based on 24000 DSCF/ton dry coal input to the dryer (1121) and 11,822 TPD dry coal to the dryer and gasifier, .608 TPD of particulates are emitted. Based on .535 lb NO_x/1.0E06 Btu coal fired (1121), 3.5 percent S coal, and 156 TPD coal for dryer fuel, .948 TPD NO_x and 10.9 TPD SO_2 are also released from the thermal dryer.

Sulfur Recovery Plant

Based on the use of the Hot Carbonate acid gas removal system for nonselective removal of H_2S and CO_2 from the synthesis gas stream, a dilute (5 percent) H_2S gas stream can be sent to the Claus plant for recovery and from (8303,AI-25) this Claus unit can recover 84 percent of the incoming S. The incoming S for recovery is based on 12892 TPD coal to the gasifier, 3.5 percent S in the coal, and all of the S to the gasifier as H_2S to Claus for recovery from (8305,61). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 619 TPD S is in the Claus feed. Thus 520 TPD S is recovered for sale or 1487 ton S/1.0E12 Btu. Since 99 TPD S passes to the Wellman Lord tailgas scrubbing unit, 4.9 TPD S or 9.8 TPD SO_2 exits the stack.

Storage and Misc.

Based on 12224 TPD coal to the gasifier and 1.37 percent N_2 in the coal (8305,60,63) and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 142 TPD NH_3 is produced in the gasifier. This value was used in this coal analysis. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .142 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operations, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8465 Based on 15386 TPD coal with 11.2 percent ash, 1723 TPD ash are produced. Since 2 TPD is released to the atmosphere as particulate, 1721 TPD remains as solid waste for disposal. Based on 10385 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 31.2 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 1867 TPD or 5340 ton/1.0E12 Btu.

8466 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 15,386 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 3.05 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8465 for solid waste.)

8467 From (8300) and (8311) the total heat demand for a plant producing 237.0E09 Btu/D of SNG is estimated to be 3976 TPD coal and the TPD coal to the gasifier is 16915. This analysis is for a weakly caking bituminous coal with 74.6 percent volatile matter and fixed carbon and a heating value of 10190 Btu/lb. Based on footnote 8450, the assumption that this coal is not too strongly caking for use in a Lurgi gasifier, and the assumption that the gasifier outputs are the same for equivalent TPD of volatile and fixed carbon input to the gasifier (since these are the reactive constituents in the coal), the Central analysis would require 15700 TPD coal to the gasifier. Based on the assumption that the total plant heat demand is relatively constant for the various bituminous coal inputs, 3565 TPD coal is required for boiler fuel. Thus a total of 19265 TPD coal is required to produce 237E09 Btu/D SNG for a primary efficiency of .541. This size plant also produces 61700 GPD of light oils (8300). If this fuel is considered, then the overall plant efficiency becomes .555. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

8468 The principal quantifiable air pollutant sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.60	11.9	1.78	.534	32.1	.00889
Sulfur Recovery Plant		4.2				
Storage and Misc.				.001		.187

Fuels Combustion

Based on air emissions factors in (8301,1.1-3) and the combustion of 3565 TPD coal (11.2 percent ash, 3.5 percent S). Particulates were reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord wet scrub, while SO_2 emissions were reduced 95 percent by the Wellman Lord unit.

Sulfur Recovery Plant

Based on the use of the Rectisol acid gas removal system for the selective removal of H_2S and CO_2 from the synthesis gas stream, a concentrated (25 percent) H_2S gas stream can be sent to the Claus plant for recovery (8308,21), and from (2022,103) this Claus unit can recover 94 percent of the incoming S. The incoming S for recovery is based on 15700 TPD coal to the gasifier, 3.5 percent S coal, and 98 percent of the S to the gasifier as H_2S to Claus for recovery (the balance of the S is in the by-products) from (8310). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 691 TPD S is the Claus feed. Thus 649 TPD S is recovered for sale or 1483 ton S/1.0E12 Btu. Since 41 TPD S passes to the Wellman Lord tailgas scrubbing unit, 2.1 TPD S or 4.2 TPD SO_2 exits the stack.

Storage and Misc.

From (8300) 6.17E04 GPD of light oils are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Based on 15700 TPD coal to the gasifier and 1.4 percent N_2 in the coal and 70 percent of the N_2 in the feed coal as NH_3 (8303,X-7), 187 TPD NH_3 is produced in the gasifier. Substantially all of this NH_3 is recovered in a free and fixed ammonia still. From (8301,5.2-2) controlled storage and loading operations emit 2 lb of NH_3/ton NH_3. Thus .187 TPD NH_3 are released into the atmosphere.

It should be noted that other sources of air pollution will be present in any commercial coal gasification operation, although their quantification is not possible at present. These sources include, but are not limited to, coal and other solids preparation and transfer operation, vent stacks for waste gas disposal, pipeline valves and flanges, and pump and compressor seals. The magnitude of these air pollutants, however, should not be that large if the sources are properly controlled.

8469 Based on 19265 TPD coal with 11.2 percent ash, 2158 TPD ash are produced. Since 2 TPD is released to the atmosphere as particulate, 2156 TPD remains as solid waste for disposal. Based on 12430 GPM net makeup H_2O (8300) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 37.3 TPD of solid waste is generated. From (8304) an ammonia still is estimated to produce 115 TPD of still waste. It is assumed that all bio-treating sludges are used as boiler fuel. The sum total solid waste produced is thus 2308 TPD or 5271 ton/1.0E12 Btu.

8470 Land requirements are assumed to be 350 acres from (9401,7) for coal storage, preparation, and gasification plant facilities. Since High Btu Coal Gasification is assumed to be a mine-mouth activity, all solid waste produced is returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 350 acres is required for a 19265 TPD coal gasification operation. With a 90 percent operating factor this is equivalent to 2.43 acre-yr/1.0E12 Btu. However, a larger land impact would be produced if solid wastes were not returned to the mine for burial. (See footnote 8469 for solid waste.)

FTN. 8471

8471 Water pollutants are based on the following process waste water analysis:

Contaminant	Waste Water-PPM	Reference	Effluent-PPM
Phenols	9960	(8310)	0.498
Cyanide	-	(8303,X-9)	-
Thiocyanates	-	(8303,X-9)	-
NH_3	15900	Calculated	15.9
Sulfide	1400	(8307,4)	1.4
Oil	1100	(8303,X-3)	15.4
Sus. Solids	600	(8307,4)	33.5

The following waste water treatment system was utilized to achieve the above effluent values - 3 stages of tar-oil-water separation, filtration, a Phenosolvan recovery unit, free and fixed ammonia stills, and activated carbon. Three stages of tar-oil-water separation were used to insure complete separation of the tars, oils, and process waste water (8310,III-08-1). Filtration and a Phenosolvan unit was employed to recover the concentrated phenols from the wastewater stream. A free and fixed ammonia still was used for substantially complete NH_3 recovery. An activated carbon system was used for a final polish. TPD emissions are based on 1 ton H_2O/ton coal to the gasifier (15700 TPD) and 75 percent of this H_2O as process wastewater condensate (11775 TPD) from (8320). Other dissolved solids TPD emissions are based on a makeup H_2O requirement of 12430 GPM (8300), an assumed influent TDS loading of 500 PPM, and a contribtuion of dissolved solids by the gasification facility of 50 percent of the incoming TDS (similar to refinery operations (8317,8) and also from (1900)). These ODS are contributed by ion exchange regenerants, treating chemicals, corrosion and scale inhibitors, etc. Organics comprise phenols and oil, while total dissolved solids includes NH_3, sulfide, and other dissolved solids. Wastewater system removal efficiencies were developed from (2013,IV-3), (8316,172), (8322,1068), and (8318,Table 7). Tons/1.0E12 Btu are based on a plant input of 19265 TPD coal.

8472 Primary efficiency and ancillary energy for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8473 Air pollutants for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8474 Solid waste production for this process is an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8475 Land utilization for this process is an arithmetic average of those used by the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8476 Water pollutants are based on the following process waste water analysis:

Contaminant	Waste Water-PPM	Reference	Effluent-PPM
Phenols	2600	(8307,4)	0.006
Cyanide	0.6	(8307,4)	0.3
Thiocyanates	152	(8307,4)	0.0
NH_3	17040	Calculated	17.0
Sulfide	1400	(8307,4)	0.01
Oil	1100	(8303,X-3)	3.7
Sus. Solids	600	(8307,4)	4.3

The following waste water treatment system was utilized to achieve the above effluent values - 3 stages of oil-water separation, dissolved air flotation, free and fixed ammonia stills, equalization, activated sludge and clarification, and char polishing tower. Three stages of oil-water separation were used to insure complete separation of the tars and process waste water (8310,III-08-1). An air flotation unit was used to further remove oil and suspended solids (8311,3.21). Based on coke plant experience (1119), (8312), and (8313,618), ammonia removal appears to be the key to treatment of weak ammonia liquor. Since the above process waste water is very similar to WAL, a free and fixed ammonia still operation was employed. Phenol biodegradation in an activated sludge unit has been successfully demonstrated on coke plant WAL (8312, 202). Complete thiocyanate removal is possible by biodegradation of WAL that has previously been deammoniated (8313,618). TPD emissions are based on 1 ton H_2O/ton coal to the gasifier for a Typical New Process (15370 TPD) and 60 percent of this H_2O as process waste water condensate (9220 TPD) from (8314). Other dissolved solids TPD emissions are based on a Typical New Process makeup H_2O requirement of 9800 GPM (8300), an assumed influent TDS loading of 500 PPM, and a contribution of other dissolved solids by the gasification facility of 50 percent of the incoming TDS (similar to refinery operations (8317,8) and also from (1900)). These ODS are contributed by Ion exchange regenerants, treating chemicals, corrosion and scale inhibitors, etc. Organics comprise phenols and oil, while total dissolved solids includes cyanide, thiocyanates, NH_3, sulfide, and other dissolved solids. Waste water system removal efficiencies were developed from (2013,IV-3), (8316,172), (8318,Table 7) and (8313, 609,618). Tons/1.0E12 Btu based on an average plant input of 16950 TPD coal.

8477 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-15,400 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for the feed system, gasification and CO shift, methanation, O_2 manufacture, steam and power plant, general utilities, and general offsites total 119.2E06 $. From (8305), escalated at 5 percent/year from 1970 to 1972 $, costs for coal storage and preparation and gas purification total 46.2E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 14.7E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 234.0E06 $. Based on a FCR of 10 percent/yr and 5.05E06 TPY coal this is equivalent to 2.04E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-15,400 TPD, 90 P LF

From (8300) the following costs were taken directly - other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor - for a total of $.053/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus $.2049/1.0E06 Btu gas or 15.82E06 $/yr for a 235.8E09 Btu/D SNG plant. By-products are credited at $10/LT for S (464 LTS/D) and $25/T NH_3 (142.3 TPD NH_3) from (8303,AI-5). The total net operating cost is therefore $13.13E06/yr or,for a 5.05E06 TPY coal input, 1.14E05 $/1.0E12 Btu.

8478 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-17,900 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal storage and preparation, pretreatment, feed system, gasification and CO shift, methanation, steam and power plant, general utilities, and general offsites total 175.6E06 $. From (8300) cost for gas purification is estimated at 22.9E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 20.9E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 282.0E06 $. Based on a FCR of 10 percent/yr and 5.88E06 TPY coal this is equivalent to 2.11E05 $/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-17,900 TPD, 90 P LF

From (8300) the following costs were taken directly-other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of \$.048/1.0E16 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus \$.2195/1.0E06 Btu gas or 18.22E06 \$/yr for a 253.3E09 Btu/D SNG plant. By-products are credited at \$10/LT for S(400 LTS/D), \$4/LT for SO_2 (216 LT SO_2/D), \$25/T NH_3 (165 TPD NH_3), \$.15/gal for B-T-X (52.5E03 GPD), and \$.30/1.0E06 Btu for tars (9.84E09 Btu/D)from (8303,AI-5). The total net operating cost is therefore \$11.72E06/yr or,for a 5.88E06 TPY coal input, 8.78E04 \$/1.0E12 Btu.

8479 Capital and operating costs were developed as follows:

Capital Costs-1972 \$-Plant Basis-17,100 TPD, 90 P LF

From (8300), escalated from 1971 \$ to 1972 \$ at 5 percent,costs for coal storage and preparation, pretreatment, feed system, gasification and CO shift, methanation, oxygen manufacture, steam and power plant, general utilities, and general offsites total 132.4E06 \$. From (8300) cost for gas purification is estimated at 22.9E06 \$. Water pollution control costs were estimated at 11.7E06 \$ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 \$) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 20.4E06 \$ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) development contingency to arrive at a total plant investment of 228.6E06 \$. Based on a FCR of 10 percent/yr and 5.61E06 TPY coal this is equivalent to 1.80E05 \$/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-17,100 TPD, 90 P LF

From (8300) the following costs were taken directly-other raw materials, catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.046/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, superivision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus $.1933/1.0E06 Btu gas or 15.70E06 $/yr for a 247.2E09 Btu/D SNG plant. By-products were credited at $10/LT for S (357.1 LTS/D), $4/LT for SO_2 (185 LT SO_2/D), $25/T NH_3 (147.5 TPD NH_3), $.15/gal for B-T-X (46E03 GPD), and $.30/1.0E06 Btu for tars (8.84E09 Btu/D) from (8303,AI-5). The total net operating cost is therefore $9.93E06/yr or,for a 5.61E06 TPY coal input, 7.80E04 $/1.0E12 Btu.

8480 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-17,600 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal storage and preparation, feed system, gasification and CO shift, gas purification, methanation,compression, oxygen manufacture, steam and power plant, general utilities, and general offsites total 153.8E06 $. Water pollution control costs were estimated at 11.7E06 $ with oil-water separation and dissolved air flotation costs from (2013,VII-5), costs for free and fixed NH_3 stills, equalization, activated sludge plus clarification, and char polishing from (8304), and a miscellaneous allowance (2.1E06 $) for water impounding basins,thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 23.3E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal were added a 15 percent (of subtotal) project contingency and a 7 percent (of subtotal) developement contingency to arrive at a total plant investment of 230.3E06 $. Based on a FCR of 10 percent/yr and 5.78E06 TPY coal this is equivalent to 1.75E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-17,600 TPD, 90 P LF

From (8300) the following costs were taken directly - catalysts and chemicals, purchased raw H_2O, and process operating labor-for a total of $.064/1.0E06 Btu gas. From (8303,AI-5) maintenance labor was based on 1.5 percent/yr of total plant investment, supervision labor was based on 15 percent of process operating and maintenance labor, administration and general overhead was based on 60 percent of total labor, operating supplies were based on 30 percent of process operating labor, and maintenance supplies were based on 1.5 percent/yr of total plant investment. The total gross operating cost is thus $.2204/1.0E06 Btu gas or 16.75E06 $/yr for a 231.8E09 Btu/D SNG plant. By-products were credited at $10/LT for S (507.1 LTS/D), $25/T NH_3 (173.6 TPD NH_3), $.15/gal for B-T-X (25000 GPD), and $.30/1.0E06 Btu for tars (13.9E09 Btu/D) from (8303,AI-5). The total net operating cost is therefore $11.00E06/yr or, for a 5.78E06 TPY coal input, 8.37E04 $/1.0E12 Btu.

8481 Capital and operating costs for this process are an arithmetic average of those for the Hygas-Electrothermal, Hygas-Steam Oxygen, Bigas, and Synthane processes.

8482 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-19,300 TPD, 90 P LF

From (8300), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal storage and preparation, gasification and CO shift, gas purification, methanation, compression, oxygen manufacture, general utilities, and general offsites total 181.5E06 $. Steam and power plant cost was estimated at 24.7E06 $ from (8300) and (8323,42). Water pollution control costs were estimated at 13.8E06 $ with tar-oil-water separation and activated carbon costs from (2013,VII-4), costs for free and fixed ammonia stills from (8304), costs for filtration and a Phenosolvan unit from (8320), and a miscellaneous allowance (2.1E06$) for water impounding basins, thickeners, settlers, etc. from (8315). Sulfur recovery costs were estimated at 17.5E06 $ from (8300) and (8303,AI-25,AI-26). To the subtotal was added a 15 percent project contingency to give a total plant investment of 273.1E06 $. Based on a FCR of 10 percent/yr and 6.33E 06 TPY coal, this is equivalent to 1.90E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-19,300 TPD, 90 P LF

From (8300) costs for catalysts and chemicals, purchased raw water, and process operating labor total $.059/1.0E06 Btu gas. Costs for maintenance labor, supervision labor, administration and general overhead, and operating and maintenance supplies were developed from (8303,AI-5). Electric power operating and maintenance costs are from (1918,46). The total gross operating cost is thus $.2336/1.0E06 Btu gas or $18.15E06/yr for a 252E09 Btu/D SNG plant. By-products were credited at $10/LTS (580 LTS/D), $25/T NH_3 (187 TPD NH_3), and $.15/gal B-T-X (61.7E03 GPD) from (8303, AI-5). The total net operating cost is thus $11.67E06/yr or,for 6.33E06 TPY coal input, 8.11E04 $/1.0E12 Btu.

8483 Thermal discharges can be completely eliminated by the use of mechanical draft wet cooling towers.

V. OIL SHALE

A. Introduction

The environmental impacts, efficiencies, and costs associated with the production of crude oil from oil shale are given in Table 3 of this report. Each process or activity data entry is based on an energy input equivalent to 10^{12} Btu/year. This is approximately 133,000 tons per year of 30 gallon per ton shale. All table entries have been derived for a "controlled" environmental condition.

Contrary to the fuels and activities described in the Phase I Report (contained in Volume I), oil shale plays a unique role in the fossil fuel trajectory. Although the oil shale task includes activities such as extraction, processing, and distribution, the end product generally cannot be considered a refined product until it is further upgraded in a conventional refinery. However,other end uses for this unrefined shale crude, such as turbine fuel for electric power generation, have been demonstrated. To be more precise, the end product considered in this report should be regarded as a high quality crude oil from which many conventional refinery products may be derived. Consequently, the oil shale task must be viewed in conjunction with the Phase I Report to complete the entire fossil fuel chain from extraction to end use.

Oil shale is a sedimentary rock consisting of a solid organic material called kerogen intimately associated with other minerals. Upon processing, this organic rich rock found in the Green River formation of Colorado, Utah, and Wyoming, will yield a low quality crude oil which is suitable for upgrading. These deposits, assaying about 30 gallons of oil per ton of shale, represent about 600 billion barrels of oil.

The recovery of crude oil from oil shale may take three distinct forms: (1) mining the oil shale and "retorting" it in surface facilities, (2) in situ retorting followed by surface upgrading, and (3) a combination of mining and in situ retorting followed by upgrading. Methods (1) and (2) are considered in this report.

Figure 20 is a flow diagram of the principal processes involved in a commercial size oil shale operation using the Gas Combustion Method. For the TOSCO II and In Situ Methods for which data have been obtained, the flow diagram will be similar.

The processing steps include the following activities.

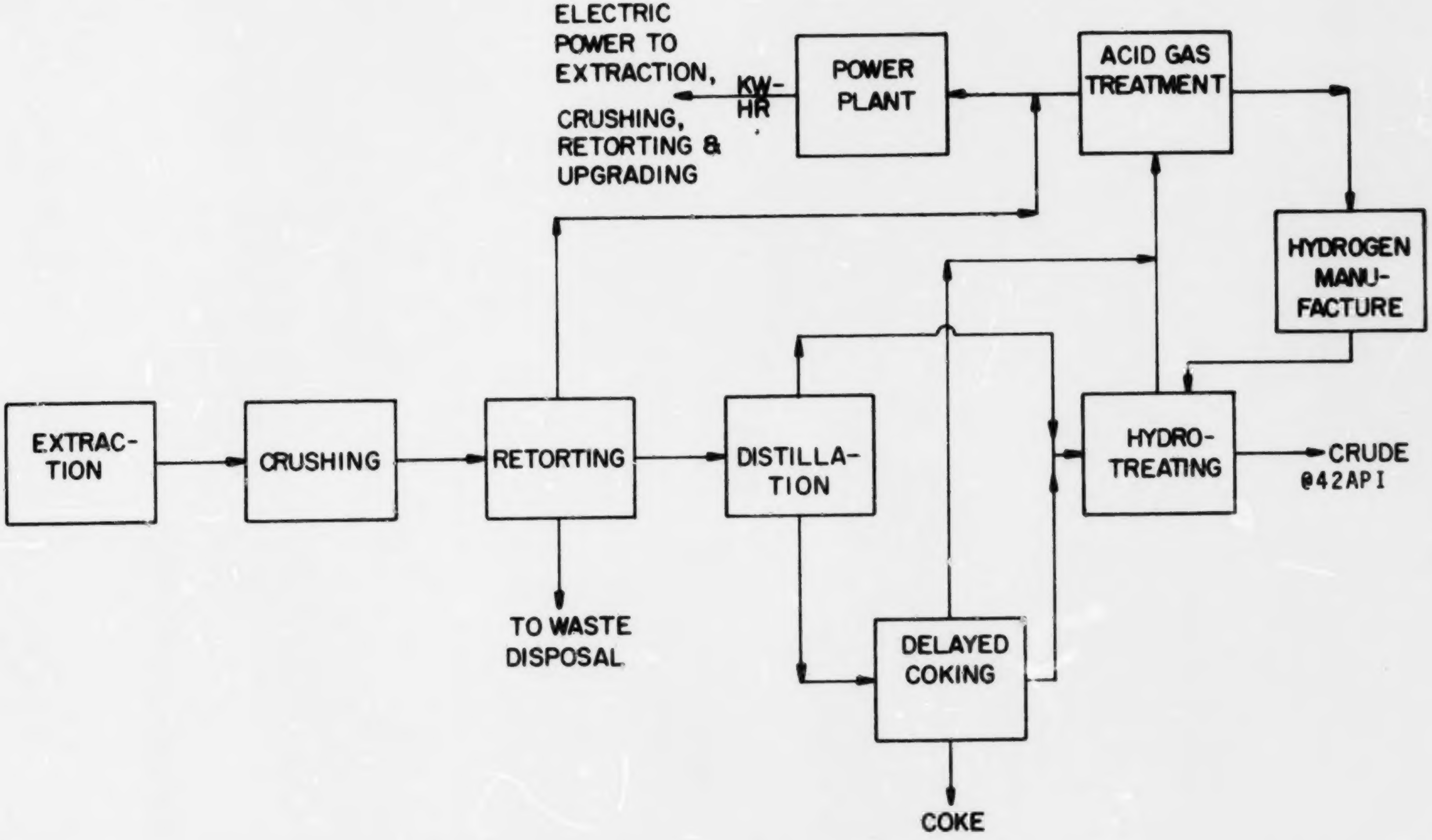
ELECTRIC POWER TO EXTRACTION, CRUSHING, RETORTING & UPGRADING
KW-HR
POWER PLANT
ACID GAS TREATMENT
HYDROGEN MANU-FACTURE
EXTRAC-TION
CRUSHING
RETORTING
DISTILLA-TION
HYDRO-TREATING
CRUDE @42API
TO WASTE DISPOSAL
DELAYED COKING
COKE

Figure 20. Typical Oil Shale Process Flow Diagram

1. Mining

This will include both underground (room and pillar) and open pit mining depending on the size of the operation and specific topography. Underground mining will essentially be associated with a 50,000 BPSD surface plant and open pit mining should support a 100,000 BPSD operation. Mining will essentially follow conventional methods, however, the magnitude of the operation will be considerably larger than present day coal or copper extraction activities. For a 100,000 BPSD plant, approximately 145,000 tons per day of oil shale must be mined and conveyed to the retorting plant.

The reader is cautioned that the impacts for the extraction process are not based on the recovery of 10^{12} Btu, but the "attempt" to recover 10^{12} Btu. Impacts for this activity are actually derived by extracting 10^{12} Btu of the resource and multiplying by the appropriate extraction efficiency so as to be consistent with all other entries in the tables, i.e. 10^{12} Btu into each activity.

2. Retorting

There are basically three methods for retorting oil shale to obtain the low quality syn-crude suitable for upgrading.

a. Gas Combustion

This method developed by the Bureau of Mines and Union Oil Company utilizes crushed shale that is charged into a processing unit or retort where it is heated to its pyrolysis temperature of between 800-1000°F. The kerogen is liberated from the inorganic matter and is converted to a gas and oil mist. These organic-rich vapors are collected and condensed to form a low gravity, moderate sulfur, high nitrogen crude oil. Combustion is supported by recycling a portion of the low Btu gas produced during retorting. Solid waste or spent shale is automatically removed and conveyed to a disposal site.

b. TOSCO II

This method, developed by the Oil Shale Corporation and sponsored by the Atlantic-Richfield Company as well as other major oil companies, involves the same approach as Gas Combustion but utilizes a different technique. The TOSCO II method utilizes hot ceramic balls to sustain pyrolysis. As the kerogen is released the balls are segregated from the spent shale, reheated and recycled. The syn-crude is further upgraded while the spent shale is conveyed to a disposal site.

c. In Situ

This method of shale oil recovery has been sponsored by the Bureau of Mines, Mobil, Shell, Equity, and other major oil companies. It involves hydraulic, explosive, or electrical fracturing of the oil shale bed, and combusting the oil shale in the ground by means of injecting natural gas and air into the well. As combustion of the oil shale takes place the shale oil is released from the inorganic material and is recovered via a series of well systems. No spent shale or ash is generated in this process.

Due to the inadequate data available on fracturing, it has not been considered in this report. The data compiled deal primarily with the retorting, recovery, and upgrading activities of the In Situ process. The generalized In Situ for which data have been compiled is not to be confused with the Occidental Petroleum process of In Situ retorting. The latter is a combination of room and pillar mining and In Situ retorting.

3. Waste Disposal

One of the major problems with above ground retorting is the large volume of spent shale that is generated. For every barrel of syn-crude produced there are approximately 1.2 tons of spent shale generated. This spent shale must be conveyed to a shale disposal site, compacted, and eventually revegetated.

4. Upgrading

Crude shale oils produced by retorting typically have high pour points and tend to form sludges if stored for prolonged periods of time. This property necessitates refining or partial refining soon after production. Hydrotreating using established techniques of the petroleum industry is best suited for reducing the pour point, removing nitrogen and sulfur, and preventing deterioration. The crude from the "retorts" is heated in a tube still and charged into a distillation column. The lighter distillates resulting are fed directly to the hydrotreating unit, whereas the heavy bottom fractions are coked prior to hydrotreating. The resulting product, a semi-refined crude having a 42°API gravity, is then stored for pipeline shipment to conventional refineries for further upgrading.

5. Power Generation

Above ground retorting (TOSCO II and Gas Combustion) methods produce sufficient quantities of fuel gas to supply the plant's steam and electrical requirements. (More recent data from the Colony Development Operation suggests that this may not be the case. See the discussion below.) In situ retorting requires an additional amount of ancillary fuel for its operation. It is assumed in this study that the fuel utilized will be natural gas supplied by a nearby pipeline system. In actuality if the semi-refined crude was utilized to produce electrical power and steam by definition it would not be considered an ancillary fuel.

The cost data presented in Table 3 are based on a 90 percent plant load factor, or 328 operating days/yr. The values presented in this table are based on data accumulated during the Fall of 1973. Since this data base was prepared, extensive work has taken place on the development of an oil shale industry. In particular, the design of the Colony Development Operation shale oil complex has resulted in a more recent and complete evaluation of environmental impacts. This information is contained in An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado. Data from this report, in general, differs from that contained herein.1)

The reader should take special care in using some of the data presented in Table 3. In particular, rows 9, 18, and 27 define impacts with respect to the processing of raw shale into semi-refined crude oil. Each of these rows (9,18 & 27) is a composite of impacts due to individual processes required in this activity. The eight rows following each of the above three rows (rows 10 thru 17, 19 thru 26, and 28 thru 35) describe the impacts of each of the processes on the basis of 1.00E+12 Btu input to each process. In trajectory type calculations, one must make use of the composite data in rows 9, 18 and 27.

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1) Letter to M.I. Singer, CEQ, dated 10/30/74 from W.E. Wade, Jr., manager planning and control, the Atlantic Richfield Co.

B. Impact Data Table and Footnotes

FUEL	REGION
OIL SHALE	

ROW	MNE-MON.	ACTIVITY PROCESS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX COL 12)												AIR P		
					DISSOLVED SOLIDS				SUSPENDED SOLIDS		TOTAL COL'S 6,7,8						
			ACIDS	BASES	PO_4	NO_3	OTHER	TOTAL (DS)		ORGANICS		BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	SO_x
1	EXTRC	EXTRACTION															
2	UNDER	UNDERGROUND	0.00+00 3 9003	0.00+00 3 9003	0.00+00 3 9003	0.00+00 3 9003	0.00+00 3 9003	0.00+00 3	0.00+00 3 9003	0.00+00 3 9003	0.00+00 3	0.00+00 3 9003	0.00+00 3 9003	0.00+00 2 0997	3.54 01 3 9001	7.61 02 3 9002	5.47 03
3	SURFC	SURFACE	0.00+00 3 9008	0.00+00 3 9008	0.00+00 3 9008	0.00+00 3 9008	0.00+00 3 9008	0.00+00 3	0.00+00 3 9008	0.00+00 3 9008	0.00+00 3	0.00+00 3 9008	0.00+00 3 9008	0.00+00 2 0997	1.33 02 4 9505	3.79 01 4 9509	2.77 02 4
4	TRNSP	TRANSPORTATION															
5	CONVY	CONVEYOR	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	4.81 01 3 9018	0.00+00 2 0997	0.00+00 2
6	TRUCK	TRUCK	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	1.42 02 4 9019	4.04 01 4 9019	2.94 02 4
7	PPROS	PRE-PROCESSING															
8	CRUSH	CRUSHING	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2	0.00+00 2 9026	0.00+00 2 9026	0.00+00 2 0997	8.40 01 2 9025	0.00+00 2 0997	0.00+00 2
9	PGASC	PROCESSING-GAS COMBUSTION	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3	0.00+00 2 9082	0.00+00 3 9082	0.00+00 3	0.00+00 3 9082	0.00+00 3 9082	0.00+00 2 9055	4.04+00 3 9083	3.55+01 3 9083	[illegible] 3
10	RETRT	RETORTING	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 0997	0.00+00 3 9030	0.00+00 3 9032	0.00+00 3
11	DSTIL	DISTILLATION	0998	0998	0998	0998	6.04-01 3 9054	6.04-01 3	0999	4.30+00 3 9054	4.91+00 3	1.73 03 3 9054	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
12	COKIG	DELAYED COKING	0998	0998	0998	0998	4.77-01 3 9058	4.77-01 3	0999	2.47 02 3 9058	5.02 01 3	0999	1.02+00 3 9058	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
13	H2MFG	HYDROGEN MANUFACTURE	0998	0998	0998	0998	0998	0999	0999	0999	0999	0999	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
14	HYTRT	HYDROTREATING	0998	0998	0998	0998	6.04-01 3 9064	6.04-01 3	0999	7.33-01 3 9064	1.34+00 3	8.63-02 3 9064	1.72+00 3 9064	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
15	GASTR	GAS TREATING	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9055	0.00+00 2 9072	0.00+00 2 9056	[illegible] 2
16	TNKCR	CRUDE STORAGE	0998	0998	0998	0998	0998	0999	2 0997	0999	0999	7.21-02 2 9033	0999	0.00+00 2 9055	0.00+00 1 0997	0.00+00 2 0997	0.00+00 1
17	POGEN	POWER GENERATION	0.00+00 3 1917	0.00+00 3 1917	0999	0999	1.40+00 4 1917	1.40+00 4	0.00+00 3 1917	1.02-03 3 1917	1.40+00 4	0999	0999	0.00+00 3 [illegible]	2.15+01 3 9031	1.89+02 3 9031	1.15+02 3
18	PTOSC	PROCESSING TOSCO II	0.00+00 3 9094	0.00+00 3 9094	0.00+00 3 9094	0.00+00 3 9094	0.00+00 3 9094	0.00+00 3	0.00+00 3 9094	0.00+00 3 9094	0.00+00 3	0.00+00 3 9094	0.00+00 3 9094	0.00+00 2 [illegible]	[illegible] 3 9088	1.29-01 3 9084	[illegible] 3
19	RETRT	RETORTING	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2	0.00+00 2 9029	0.00+00 2 9029	0.00+00 2 0997	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3
20	DSTIL	DISTILLATION	0998	0998	0998	0998	6.04-01 3 9054	6.04-01 3	0999	4.30+00 3 9054	4.91+00 3	1.73 03 3 9054	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
21	COKIG	DELAYED COKING	0998	0998	0998	0998	4.77-01 3 9058	4.77-01 3	0999	2.79 02 3 9058	5.62 01 3	0999	1.02+00 3 9058	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
22	H2MFG	HYDROGEN MANUFACTURE	0998	0998	0998	0998	0998	0998	0999	0999	0999	0999	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
23	HYTRT	HYDROTREATING	0998	0998	0998	0998	6.04-01 3 9064	6.04-01 3	0999	7.33-01 3 9064	1.34+00 3	8.63-02 3 9064	1.72+00 3 9064	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2
24	GASTR	GAS TREATING	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9055	0.00+00 2 9072	0.00+00 2 9072	[illegible] 2 9072
25	TNKCR	CRUDE STORAGE	0998	0998	0998	0998	0998	0999	0999	0999	0999	7.21-02 2 9033	0999	0.00+00 2 9055	0.00+00 1 0997	0.00+00 2 0997	0.00+00 1 0997
26	POGEN	POWER GENERATION	0.00+00 3 1917	0.00+00 3 1917	0999	0999	1.40+00 4 1917	1.40+00 4	0.00+00 3 1917	1.02-03 3 1917	1.40+00 4	0999	0999	0.00+00 3 [illegible]	7.62+00 3 9032	1.90+02 3 9031	5.22+02 3 9032
27	PINST	PROCESSING IN SITU	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3	0.00+00 3 9082	0.00+00 3 9082	0.00+00 3	0.00+00 3 9082	0.00+00 3 9082	0.00+00 2 9055	[illegible] 3 9085	[illegible] 9085	[illegible] 3 9085
28	RETRT	RETORTING	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2	0.00+00 2 9079	0.00+00 2 9079	0.00+00 2 0997	[illegible] 3 9078	0999	[illegible] 3 9070
29	DSTIL	DISTILLATION	0998	0998	0998	0998	6.04-01 3 9054	6.04-01 3	0999	4.30+00 3 9054	4.91+00 3	1.73-03 3 9054	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2 9056
30	COKIG	DELAYED COKING	0998	0998	0998	0998	4.77-01 3 9058	4.77-01 3	0999	2.79-02 3 9058	5.02-01 3	0999	1.02+00 3 9058	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2 9056
31	H2MFG	HYDROGEN MANUFACTURE	0998	0998	0998	0998	0998	0998	0999	0999	0999	0999	0999	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	0.00+00 2 9056
32	HYTRT	HYDROTREATING	0998	0998	0998	0998	6.04-01 3 9064	6.04-01 3	0999	7.33-01 3 9064	1.34+00 3	8.63-02 3 9064	1.72+00 3 9064	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 9056	[illegible] 2 9072
33	GASTR	GAS TREATING	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2	0.00+00 2 9071	0.00+00 2 9071	0.00+00 2 9055	0.00+00 2 9056	0.00+00 2 0997	0.00+00 1 0997
34	TNKCR	CRUDE STORAGE	0998	0998	0998	0998	998	0999	0999	0999	0999	7.21-02 2 9033	0999	0.00+00 2 9055	7.39+02 3 1901	1.91-02 3 1901	2.91-03 3 1901
35	STMGN	STEAM GENERATION	0.00+00 3 1917	0.00+00 3 1917	0999	0999	1.40+00 4 1917	1.40+00 4	0.00+00 3 1917	1.02-03 3 1917	1.40+00 4	0999	0999	0.00+00 3 [illegible]			
36	DISTB	DISTRIBUTION															
37	PIPLN	PIPELINE	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	3.61 01 3 9038	4.56+00 3 9038	1.34 01 3 9038
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	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
MAL BTU	PARTIC-ULATES	NO_x	SO_x	HYDRO-CARBONS	CO	ALDEHYDES ETC.	TOTAL	SOLIDS TONS/ 10^{12}BTU	LAND (ACRE-YR / 10^{12} BTU)	DEATHS / 10^{12} BTU	INJURIES / 10^{12} BTU	MAN-DAYS LOST/10^{12}BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY (BTU/10^{12}BTU)	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
2 0997	3.34-01 3 9001	7.41-02 3 9002	5.47-03 3 9002	7.74-03 3 9002	4.55-02 3 9002	6.39-04 3 9002	4.89-01 3	1.73-01 2 9005	[illegible]-09 2 9006	4.14-03 3 9006	1.09-01 3 9006	0998	[illegible]	6.50-01 2 9000	1.27+09 3 9007	7.74+03 3 9047	7.93+04 3 9047	8.74+04 3	2
2 0997	1.33-02 4 9009	1.76-01 4 9009	2.77-02 4 9009	3.79-02 4 9009	2.31-01 4 9009	3.08-03 4 9009	1.12+00 4	[illegible]+04 2 9010	[illegible] 2 9011	1.06-01 3 9012	5.44-02 3 9012	0998	1081	6.20-01 2 9013	5.66+08 3 9014	8.43+03 3 9048	3.03+04 3 9048	3.87+04 3	3
																			4
2 0997	4.81-01 3 9018	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	4.80-01 3	0.00+00 2 0997	4.00-02 3 9017	0999	0999	0999	1082	1.00+00 2 9016	1.31+09 2 9015	1.49+03 2 9049	1.46+02 2 9049	1.64+03 2	5
2 0997	1.42-02 4 9019	4.04-01 4 9019	2.94-02 4 9019	4.34-02 4 9019	2.45-01 4 9019	3.27-03 4 9019	7.36-01 4	0.00+00 2 0997	2.00-02 3 9020	0999	0999	0999	1082	1.00+00 2 9021	3.02+08 2 9022	2.46+03 3 9050	6.74+03 3 9050	9.20+03 3	6
																			7
2 0997	4.40-01 2 [illegible]	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	0.00+00 2 0997	4.40-01 2	1.73-01 2 9027	8.24-02 4 9028	0999	0999	0999	1082	9.87-01 2 9024	[illegible]+08 3 9023	6.77+03 3 9051	1.33+03 4 9051	8.10+03 4	8
2 9055	4.94+00 3 9081	1.55-01 3 9081	[illegible] 3 9081	[illegible]-01 3 9081	3.65-02 3 9083	2.75-01 3 9083	[illegible]+01 3	[illegible]+05 2 9040	1.78+00 1 9087	1.46-01 3 9090	1.55-01 3 9090	4.44-01 3 9090	0999	5.31-01 2 9095	0.00+00 2 9097	1.18+05 3 9101	3.32+05 3 9101	4.89+05 3	9
2 0997	[illegible] 3 9030	0.00+00 3 9032	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3	1.08+05 2 9040	5.50-02 3 9043	1.37-03 3 9042	1.44-01 3 9042	0999	0999	6.73-01 2 9044	2.33+10 2 9046	6.84+04 3 9052	1.04+05 3 9052	1.68+05 3	10
2 9055	[illegible] 2 9056	0.00+00 2 9056	0.00+00 2 9056	2.73+00 3 9054	0.00+00 2 9056	0.00+00 2 9056	2.73+00 3	0998	0999	0999	0999	0999	2091	1.00+00 2 9105	1.90+10 3 9054	9.05+03 3 9057	2.50+04 3 9057	3.41+04 3	11
2 9055	[illegible] 2 9056	0.00+00 2 9056	0.00+00 2 9056	2.13+00 3 9059	0.00+00 2 9056	0.00+00 2 9056	2.13+00 3	0998	0999	0999	0999	0999	2091	8.97-01 2 9091	7.44+10 3 9069	3.86+04 3 2087	6.37+04 3 9061	1.02+05 3	12
2 9055	[illegible] 2 9056	0.00+00 2 9056	0.00+00 [illegible] 9056	[illegible]+00 3 9062	0.00+00 2 9056	0.00+00 2 9056	4.08+00 3	0998	0995	0999	0999	0999	2091	5.03-01 2 2079	1.03+12 2 2079	7.38+04 2 2052	3.34+05 2 2052	4.08+05 2	13
2 9055	[illegible] 2 9056	[illegible] 2 9052	0.00+00 2 9056	2.59+00 3 9081	0.00+00 2 9056	0.00+00 2 9056	2.59+00 3	0998	0999	0999	0999	0999	2091	9.68-01 2 9105	1.13+10 3 9065	4.17+03 3 9066	4.85+04 3 9066	5.27+04 3	14
2 9051	[illegible] 2 9073	[illegible] 2 9056	[illegible] 2 9072	0.00+00 2 9072	0.00+00 2 9072	0.00+00 2 9072	[illegible]+01 2	0.00+00 2 9073	2.55+00 4 9074	0999	0999	0999	2091	1.00+00 2 9075	0999	3.32+05 3 9076	0.00+00 3 9076	3.32+05 3	15
2 9050	[illegible]	[illegible] 2 0997	0.00+00 1 0997	5.48+00 2 9034	0.00+00 1 0997	2 0997	1.03+01 2	2 0997	4.16-01 2 9035	0995	0999	0999	2092	1.00+00 2 9036	1.54+06 4 9037	1.83+03 3 9053	2.68+03 3 9053	6.51+03 3	16
3 1918	[illegible] 3 9031	1.89-01 3 9031	1.55+02 3 9031	1.94+01 3 9031	1.94-01 3 9031	1.46+00 3 9031	1.87+02 3	0.00+00 3 0997	2.76+00 3 3904	1.96-04 3 3903	1.67-02 3 3903	2.36+00 3 3903	0999	3.80-01 2 1912	0.00+00 1 9068	2.35+05 2 2907	6.79+04 2 2907	3.03+05 2	17
2 9055	[illegible] 3 9084	1.29-01 3 9084	5.74+02 3 9084	1.22-01 3 9084	[illegible] 3 9084	9.91-02 3 9084	6.28+02 3	1.08+05 2 9040	1.78+00 3 9088	1.41-03 3 9090	1.48-01 3 9090	1.49-01 3 9090	0999	6.67-01 2 9096	0.00+00 3 9098	7.50+04 3 9102	3.73+05 3 9102	4.87+05 3	18
2 0997	[illegible] 3 9030	[illegible] 3 9030	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3 9030	0.00+00 3	1.08+05 2 9040	1.78-02 3 9041	1.37-03 3 9042	1.44-01 3 9042	0999	0999	7.76-01 2 9045	0999	0999	0999	0999	19
2 9055	[illegible] 2 9056	[illegible] 2 9056	0.00+00 2 9056	2.73+00 3 9054	0.00+00 2 9056	0.00+00 2 9056	2.73+00 3	0998	0999	0999	0999	0999	2091	1.00+00 2 9105	1.90+10 3 9054	7.99+03 3 9057	2.51+04 3 9057	3.31+04 3	20
2 9055	[illegible] 2 9056	[illegible] 2 9056	0.00+00 2 9056	2.13+00 3 9059	0.00+00 2 9056	0.00+00 2 9056	2.13+00 3	0998	0999	0999	0999	0999	2091	8.97-01 2 9091	7.44+10 3 9066	3.86+04 3 2087	6.37+04 3 9061	1.02+05 3	21
2 9055	[illegible] 2 9056	[illegible] 2 9056	0.00+00 2 9056	[illegible] 3 9062	0.00+00 2 9056	0.00+00 2 9056	4.08+00 3	0998	0999	0999	0999	0999	2091	5.03-01 2 2079	1.03+12 2 2079	7.38+04 2 2052	3.34+05 2 2052	4.08+05 2	22
2 9055	[illegible] 2 9056	[illegible] 2 9056	0.00+00 2 9056	2.59+00 3 9081	0.00+00 2 9056	0.00+00 2 9056	2.55+00 3	0998	0999	0999	0999	0999	2091	9.68-01 2 9105	1.13+10 3 9065	4.17+03 3 9066	4.85+04 3 9066	5.27+04 3	23
2 9053	[illegible] 2 9072	[illegible] 2 9072	[illegible] 2 9072	0.00+00 2 9072	0.00+00 2 9072	0.00+00 2 9072	[illegible]+01 2	0.00+00 2 9073	2.55+00 4 9074	0999	0999	0999	2091	1.00+00 2 9075	0999	3.32+05 3 9076	0.00+00 3 9076	3.32+05 3	24
2 9055	[illegible] 0997	[illegible] 2 0997	0.00+00 1 0997	5.48+00 2 9034	0.00+00 1 0997	0.00+00 2 0997	5.53+01 2	0.00+00 2 0997	4.16-01 2 9035	0999	0999	0999	2092	1.00+00 2 9036	1.54+06 4 9037	1.83+03 3 9053	2.68+03 3 9053	6.51+03 3	25
3 1914	2.42+00 3 9032	[illegible] 3 9032	5.22+02 3 9032	1.95+01 3 9032	1.95-01 3 9032	1.46+00 3 9032	7.16+02 3	0.00+00 3 0997	2.76+00 3 3904	5.96-04 3 3903	1.67-02 3 3903	2.36+00 3 3903	0999	3.80-01 2 1912	0.00+00 1 9067	2.35+05 2 2907	6.79+04 2 2907	3.03+05 2	26
2 9055	[illegible] 3 9081	[illegible] 9081	[illegible] 3 9085	[illegible] 3 9085	[illegible] 3 9085	[illegible] 3 9087	[illegible] 3	0.00+00 2 0997	1.78+00 3 9089	[illegible] 3 9090	5.71-01 3 9090	[illegible]-02 3 9090	0999	5.31-01 2 9095	5.99+10 3 9099	1.11+05 3 9103	2.98+05 3 9103	4.09+05 3	27
2 0997	[illegible] 3 9078	0999	[illegible] 3 9078	[illegible] 3 9078	[illegible] 3 9078	0999	[illegible] 3	0.00+00 2 0997	[illegible] 3 9069	1.64-03 3 9070	5.69-01 3 9070	0999	0999	5.67-01 3 9086	0999	5.78+04 3 9077	0999	5.78+04 3	28
2 9055	[illegible]	[illegible] 2 9056	0.00+00 2 9056	2.73+00 3 9054	0.00+00 2 9056	0.00+00 2 9056	2.73+00 3	0998	0999	0999	0999	0999	2091	1.00+00 2 9105	1.90+10 3 9054	9.05+03 3 9057	2.50+04 3 9057	3.41+04 3	29
2 9055	[illegible]	[illegible] 9056	0.00+00 2 9056	2.13+00 3 9059	0.00+00 2 9056	0.00+00 2 9056	2.13+00 3	0998	0999	0999	0999	0999	2091	8.97-01 2 9091	7.44+10 3 9060	3.86+04 3 2087	6.37+04 3 9061	1.02+05 3	30
2 9055	[illegible]	[illegible] 9056	0.00+00 2 9056	[illegible] 3 9062	0.00+00 2 9056	0.00+00 2 9054	4.08+00 3	0998	0999	0999	0999	0999	2091	5.03-01 2 2079	1.03+12 2 2079	7.38+04 2 2052	3.34+05 2 2052	4.08+05 2	31
2 9051	[illegible]	[illegible] 9056	0.00+00 2 9056	2.59+00 3 9081	0.00+00 2 9056	0.00+00 2 9056	2.59+00 3	0998	0999	0999	0999	0999	2091	9.68-01 2 9105	1.13+10 3 9065	4.17+03 3 9066	4.85+04 3 9066	5.27+04 3	32
2 9051	[illegible]	[illegible] 9056	[illegible] 2 9072	0.00+00 2 9072	0.00+00 2 9072	0.00+00 2 9072	[illegible] 2	0.00+00 2 9073	2.55+00 4 9074	0999	0999	0999	2091	1.00+00 2 9075	0999	3.32+05 3 9076	0.00+00 3 9076	3.32+05 3	33
2 9055	[illegible]	[illegible] 0997	[illegible] 1 0997	5.48+00 2 9034	0.00+00 1 0997	0.00+00 2 0997	5.53+01 2	0.00+00 2 0997	4.16-01 2 9035	0999	0999	0999	2092	1.00+00 2 9036	1.54+06 4 9037	1.83+03 3 9053	2.68+03 3 9053	6.51+03 3	34
1 1916	[illegible] 3 1901	[illegible] 3 1901	4.95+02 3 1901	1.96+01 3 1901	1.98-01 3 1901	[illegible] 3 1901	7.22+02 3	0.00+00 3 0997	2.76+00 3 3904	[illegible] 3 3901	1.67-02 3 3901	2.36+00 3 3901	0999	8.80-01 2 9106	0.00+00 1 0997	0999	0999	0999	35
																			36
[illegible]	[illegible]-01 3 9038	[illegible] 3 9039	3.44-01 3 9038	4.34-01 3 9038	2.78+00 3 9038	5.70-02 3 9038	4.31+00 3	[illegible] 0997	6.36+01 2 2003	1.36-05 4 2034	2.79-03 4 2034	5.46-02 4 2034	2087	1.00+00 2 2081	3.63+09 3 9038	0999	[illegible]	[illegible]+04 3 2072	37
																			38
																			39
																			40
																			41
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TABLE 3. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED OIL SHALE SUPPLY

Footnotes for Table 3

1081 Large scale disasters at strip mines are rarities. As in auger mining only the failure of the highwall presents any potential for a disaster.

1082 The potential for large scale disasters is non-existent.

1906 Source-(1906,46). 0.166 men per MWE is the basis for the calculation. Injury data are from (1907,35). Half the combined deaths and permanent injuries are assumed to be fatal injuries. Permanent total disabilities are considered to represent 6000 days lost while other disabilities are estimated as 100 days lost. Man-days lost are for injuries only.

1912 A large new power plant is assumed to have a heat rate of 8960 Btu/Kw-hr, equivalent to 38P conversion efficiency. The best plants have achieved around 8530-8900, whereas the national average is around 10,500 (1913, I-5-6/I-5-7).

1917 The basis for water pollutant calculations is the proposed effluent limitations guidelines and new source performance standards for the steam electric power generating point source category given in (1921). For new plants, best available demonstrated control technology (BADCT) requires effluent pH control in the range of 6-9. Hence, acids and bases discharge will be negligible. BADCT also specifies total suspended solids levels no greater than 15 mg/l for all intermediate and low volume waste effluents. At this level of control there will generally be no net increase in suspended solids in water passing through the power plant system. Organics (oil and grease) must be controlled to 10 mg/l to meet BADCT standards. Hence, from (1921, 232) these emissions will amount to 3.02-03 ton/10^{12} Btu. Information on the increase in total dissolved solids of water used in power plants is not readily available and was synthesized from (1922,10,12,20,22). Based on this data the net increase in total dissolved solids for water used by the power plant is 3.40 ton/10^{12} Btu.

1918 Thermal discharges are assumed to be completely eliminated by the use of mechanical draft wet cooling towers.

2002 Land impact for pipeline transport of crude oil is based on 1971 total crude oil trunk and gathering line mileage of 146200 mi (2001,2) and total crude oil transported by pipeline in 1971 of 3.095E9 BBL (0005,14). Assuming an AV pipeline right-of-way of 62.5 ft (2002,14), about 63.6 AC are affected per 1.0E12 Btu shipped.

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2023 Hydrogen manufacture (steam reforming)

SCF of natural gas feed equivalent to 1.0E12 Btu is 9.69E08. (0005,38 and footnote 2000)

** Water Pollutants **

Thermal-gallons cooling water/MSCF H_2 is 650 and Delta T is 25F (2005,270)

No other water pollutant information available.

** Air Pollutants **

The air pollutant sources include steam reformer and waste heat boiler, blowdown system, pipeline valves and flanges, vessel relief valves, pump and compressor seals and process drains. Air pollutant emission factors from (0002,1-9,9-3/9-4). Natural gas was assumed to be the fuel used in the reformer and boiler.

SCF fuel required in reformer is 4.947E08. Based on (2005,270) and 1031 Btu/SCF (0005,38). Electricity at 0.4 KWH/1000 SCF fuel required in waste heat boiler is 0.0. Boiler uses waste gases from reformer (2005,270).

** Air Emissions (tons/yr) **

Component	Steam Reformer	Waste Heat Boiler	Other Sources
Particulates	4.45E+00	-	-
NO_x	5.67E+01	-	-
SO_x	1.49E-01	-	-
HC	9.89E+00	-	-
CO	9.89E-02	-	-
NH_3	0.00E+00	-	-
Other Organics	2.48E+00	-	-

With a natural gas feed of 1.0E12 Btu/yr, the hydrogen plant can make 1.83E09 SCF H_2/yr (2005,270). A 100000 BPSD refinery uses approximately 100 MMSCFD H_2.

2034 Based on 1971 data for transport of crude oil by pipeline, 83 disabling work injuries, 2517 man-days lost, 1 death (0035,4). Total crude oil transported by pipeline in 1970 is 5.298E09 BBL (0011,561). The allocation to 1.0E12 Btu/yr is 3.36E-05.

2047 Based on (9022,65) the capital cost of a 10000 BPSD delayed coker is 8.0E06 dollars and its operating cost is is 53.5 cents/BBL. Fixed charge rate is 10P. 1972 dollars. BPSD equivalent to 1.0E12 Btu/yr is 482.

2052 Based on (2010,176/182) the capital cost of a 100 MMSCFD hydrogen plant is 13.3E06 dollars and its operating cost is 18.25 cents per MSCF H_2. Fixed charge rate is 10P. 1972 dollars. SCFD H_2 resulting from 1.0E12 Btu/yr natural gas feed is 5.55E06.

2072 Based on operating revenues of $6.7E08 and 5.3E09 BBLs crude oil transported. 178000 BBL/yr equivalent to 1.0E12 Btu/yr.

2079 Based on feed and fuel requirements from footnote 2023.

2081 Based on (0012,71) 0.006P vol. is lost in leakage. Thus primary efficiency is 99.994P. From Footnote 2031, pipeline energy is 450 Btu/ton-mi. Average pipeline movement is 300 miles. Tons/yr of crude and product are 26600 and 27300 (Footnote 2074).

2087 The major cause of all pipeline accidents in 1970 was external corrosion at 43P, earth-moving equipment accounted for 20P, personnel errors 4P. Natural catastrophes such as land slides, earthquakes, and floods were of minor magnitude in their effects on pipelines. Dragging of anchor lines can rupture an offshore pipeline (2003,Chapter 6).

2091 Fire and/or explosions caused by gas leaks, oil leaks, acts of God, or human error. Possible damage to refinery, personnel, adjacent properties.

2092 Fire and/or explosions caused by sparks and improper venting. Most refinery fires and explosions are in the tank farm.

2907 Capital and operating costs for controls are estimated as follows:

Control System	Capital $/Kw	Cost-Ref	Operating Mills/Kw-hr	Cost-Ref
Water Poll-Chemical	1	(1921,233)	.05	(1921,234)
Water Poll-Thermal	10	(1915)	.05	(1920,III-3)
Total	11		.10	

Based on the above, a 60P load factor and a net plant heat rate of 9053 Btu/Kw-hr (37.7P primary efficiency from Footnote 2908) the incremental capital cost is 2.31+04 $/1.0E12 Btu and the incremental operating cost is 1.10+04 $/1.0E12 Btu. These are in addition to the costs given in Footnotes 2906 and 3905. Note that incremental fuel costs associated with purchasing a .6P sulfur residual oil (for oil fired power plants) are not included in the above analysis. Although properly attributed to air pollution control costs, the cost of fuel is not considered in the operating and maintenance costs of the uncontrolled case and hence an incremental fuel cost is not given for the controlled case.

3901 Air Emission Components (Tons/1.0E12 Btu) From (9010,I-9)

Particulates	SO_x	CO	HC	NO_x	Aldehydes, etc.
7.34	.293	.190	19.6	191	3.43

3903 See Footnote 1906, using 0.089 men per MWE.

3904 Note that the only controls utilized are cooling towers to prevent thermal discharge to water. Ten acres are needed for the cooling towers with a 1000 MWE plant. This is 6.3 percent of the total land use. Land use for a 1.0E12 Btu plant (input) has been linearly scaled from a 1000 MWE plant.

3905 Cost of gas fired power plant at $100/Kw (1914) and (1915). Operating and maintenance cost exclusive of fuel cost at 0.51 mills/Kw-hr (1906,45). A 60P load factor is assumed and the FCR for capital is 10P.

9000 The efficiency for room and pillar underground mining is 65 percent (9002,65). This figure is based on preventing subsidence within the mine.

9001 Air emissions as particulates are due to the vehicular traffic and blasting within the mine itself. For a mine processing 73,700 tons/day particulate emissions are 25 lb/hr (9000 I, III-122). For a raw oil shale heating value of 7.53E+06 Btu/ton particulate emission due to blasting within the mine is 3.51E-01 ton/1.00E +12 Btu input (9013). Using diesel trucks of 100 ton capacity (gross to tare 2.5/1) and a 1500 ft average distance between extraction and primary storage, it takes 1328 round trips to haul 1.00E+12 Btu of oil shale. Diesel particulate emissions based on 7 gal/1000 T-mi are 13 lb/1.00E+3 gal. For hauling 1.00E+12 Btu of oil shale 621 gal are consumed hence particulate emission = 2.64E-03 tons. Total emission is 3.54E-01 tons/1.00E+12 Btu (9010,3.7).

9002 Air emissions generated in the mine are generated by vehicular traffic. Exhaust fans disperse the pollutants into the atmosphere. Total pollutants based on 1328 round trips/1.00E+12 Btu (see footnote 9001) are as follows:

SO_x	5.47E-03 ton
CO	4.55E-02 ton
HC	7.74E-03 ton
NO_x	7.61E-02 ton
ALD	6.39E-04 ton

Figures based on (9010,3.5) and fuel consumption of 621 gal.

9003 Water pollutants from the underground mining operation will be negligible. If low quality mine water with TDS ranging from 200 to 63,000 PPM is encountered, it will be used for dust control and spent shale disposal, hence alleviating the need to draw high quality water from surface sources (9000). Initially mine water will be of high quality and could be released to nearby streams if necessary.

9004 Fixed land impact for an underground oil shale mine assuming no subsidence is 10 acres for a 73,700 T/D operation (9000,I-III-12). Land is for mine opening, equipment storage, maintenance bldg, etc. The incremental land impact for waste shale disposal, assuming a combination of surface disposal and return of the waste to the underground voids, is 1.93 acre yr/10^{12} Btu from (9000, I-III-18). Thus for a yearly output of 1.82E+14 Btu, the total land impact is 1.97 acre-yr/1.00E+12 Btu input.

9005 Only the overburden necessary to open the mine is considered solid waste. For 4 mine shafts each 25 ft in diameter & 1500 feet deep, 1.47E05 ton of solid waste are produced at an assumed density of .05 ton/ft^3. This is for a 73,700 TPD oil shale operation (50,000 bbl/d) so that over the 30 year lifetime of the mine the solid waste amounts to 17.5 ton/10^{12} Btu.

9006 Occupational health statistics are based on (9000,I-III-9). Over a 10 year period nonfatal and fatal accidents for underground mining are 2,919 and 63.93 respectively (9000,I-III-235). For the 10 year operation 1.00E+16 Btu are extracted from underground mines. On a 1.00E+12 Btu in basis nonfatal accidents are 1.89E-01 and fatal accidents are 4.14E-03.

9007 Ancillary energy requirements for the room and pillar mining operation consist of 4,200 Kw-h/H (9027) for operating electrical shovels, etc. This is for a 50,000 BPSD operation (73,600 T/D). On a 1.00E+12 Btu extracted basis, ancillary energy is 6.20E+08 Btu. Real energy consumption is 3 times the Btu equivalent = 1.86E+09 Btu. From footnote 9001, 621 gallons of diesel fuel is used with a heating value of 138,690 Btu/gal (9032,269). Total energy consumption is 1.27E+09 Btu/1.00E+12 Btu input.

9008 Water pollutants for the surface mining operation are zero (9000,I,I-73). Oil shale is dry and drains well. Storm water will be directed away from the surface mine by piping systems. Water obtained during mine dewatering will be used for spent shale disposal and dust control. Excess water of high quality (low in salinity) will be discharged directly to local streams and rivers. Highly saline waters may be disposed of by deep well injection or desalted and released. Contamination of ground water reservoirs by saline water is not quantifiable.

9009 Air pollutants from the surface mining operation are a result of vehicular traffic. Dust is controlled by water sprays and blasting dust generated is not quantifiable. 15 cy electric shovels are used to excavate and load the 55 ton diesel (9000) trucks. It is assumed that the average distance from shovel to portable crusher and conveying system is 2000 feet. For a gross to tare ratio of 2.5/1 and a fuel consumption of 7 gal/1000T-mi, see footnote 9001, it takes 819 gals to haul 1.33E+5 tons of oil shale. In addition to the oil shale haulage, overburden must be removed. Overburden averaging 450 ft (9000, III,III-11) and occupying 1.56E-01 acres/1.00E+12 Btu extracted (see solid waste) weighs 1.52E+05 tons assuming a density of 0.05 T/CF. For a haulage distance of 1 mile to the disposal site, the fuel consumption is 2494 gal/1.00E+12 Btu extracted. Total fuel consumption is 3313 gallons/10^{12} Btu out or 2054 gal/10^{12} Btu in.

Air emissions are as follows (9010,3.7)

Particulates	1.33E-02 tons
SO_x	2.77E-02 tons
CO	2.31E-01 tons
HC	3.79E-02 tons
NO_x	3.79E-01 tons
ALD	3.08E-03 tons

9010 Solid waste generated in the mining operation consists of overburden that must be removed to expose the oil shale. With an average overburden of 450 feet (9000, III,III-11) and an area of 28.5 acres/2.42E+07 ton/yr (9000,I,III-12) 1.56E-01 acres are overturned on a 1.00E+12 Btu extracted basis. Heating value of raw shale is 7.53E+06 Btu/ton. With a density of 0.05 ton/CF and average overburden of 450 ft, solid waste is 9.42E+04 ton/1.00E+12 Btu input. However after 16 yr (of the 30 yr lifetime) backfilling of overburden begins so that the solid waste is 5.03E04 ton/1.0E12 Btu input.

9011 The incremental land impact for waste shale and overburden disposal, assuming revegetation of the filled canyons and backfill into the mined-out pit, is 3.99 acre yr/10^{12} Btu from (9000,I-III-15).

9012 For a 10 year surface mining operation, fatal accidents will be 6.2 and non-fatal will be 320 (9000,I,III-235). Over the 10 years 3.65E15 Btu will be extracted (9000, I-III-9). Fatal and non-fatal accidents on a 1.00E+12 Btu input basis are 1.06E-03 and 5.44E-02 respectively.

9013 Efficiency of the oil shale surface mining operation is 62 percent (9000,III,III-12). This figure assumes lower grade shale oils (less than 30 gal/ton) are not processed.

9014 Ancillary energy for a surface mining operation consists of energy consumed by the electric shovels and diesel fuel used in hauling. For a large quarry shovel the energy consumption is 0.6 Kw-h/cy (9016,439). The specific volume of shale is 15 CF/T (9002,66). For excavating 1.00E+12 Btu of oil shale, 1.33E+05 tons of oil shale must be handled. At 0.60 Kw-h/cy energy consumption, ancillary energy is 9.36E+07 Btu/10^{12} Btu in. Real energy is 3 times this or 2.81E+08 Btu. Diesel fuel consumption is 2054 gal (Footnote 9009). At 138,690 Btu/gal energy consumption is 2.85E+08 Btu/1.00E+12 Btu in. Total consumption is 5.66E+08 Btu/10^{12} Btu in.

FTN. 9015-9022

9015 Ancillary energy required to move 3100 T/H over a distance of one mile, with a rise/fall of 1000 feet is 4000 HP. This is a 48 inch inclined belt conveyor system (9033). To transport 1.00E+12 Btu energy consumption is 1.28E+05 Kw-h. Real consumption is 3 times this or 1.3.E+09 Btu.

9016 Efficiency of the conveying system is 100 percent based on negligible fugitive dust losses (9000,III, III-19).

9017 For a conveying system of one mile (from mine to crushing plant) and a right of way of 60 feet, a 48 inch belt conveyor requires 7.28 acres. For a yearly output of 1.82E+14 Btu, land impacts equal 4.00E-02 acre-year/1.00E+12 Btu.

9018 Air emissions during conveying consist of fugitive dust. Enclosed conveying system will reduce dust/particulates to 20 lb/hr (9000,I,III-132). For a year output of 1.82E+14 Btu, particulate emissions = 4.80E-01 ton/1.00E+12 Btu.

9019 Air pollutants associated with oil shale haulage come solely from truck exhaust. Dust is controlled by water sprays. For hauling 1.33E+05 ton oil shale, a 100 ton truck will make 1330 trips. Assuming a distance of one mile, gross to tare ratio of 2.5/1.0, and fuel consumption of 7 gal/1000 ton-mile, fuel consumption is 2180 gal. Air pollutants are as follows (9010,3.7)

Particulates	1.42E-02 tons/1.00E+12 Btu
SO_x	2.94E-02 tons/1.00E+12 Btu
CO	2.45E-01 tons/1.00E+12 Btu
HC	4.04E-02 tons/1.00E+12 Btu
NO_x	4.04E-01 tons/1.00E+12 Btu
ALD	3.27E-03 tons/1.00E+12 Btu

Particulate emission from oil shale dust is not quantifiable and is assumed to be controlled by water sprays during loading.

9020 Land impact for a roadway one mile long and a 30 foot right of way is 2.00E-02 acre-yr/1.00E+12 Btu based on a yearly output of 1.82E+14 Btu.

9021 Primary efficiency of truck hauling is 1.00E+00 since fugitive dust losses are assumed to be negligible.

9022 From footnote 9019, diesel fuel consumption to haul 1.00E+12 Btu of oil shale is 2180 gallons. Heating value of diesel fuel is 138,690 Btu/gal (0005,38). Ancillary energy is 3.02E+08 Btu/1.00E+12 Btu.

9023 Power requirement for a plant handling 73,600 ton/day is 2090 Kw for the crushing and sizing operation (9027). This is 0.685 Kwh/ton oil shale. For a 1.33E+05 ton/1.00E+12 Btu equivalent, the energy consumption is 3.09E+08 Btu. For real consumption ancillary energy is 3 x 3.09E+08 Btu = 9.28E+08 Btu.

9024 For a crushing operation handling 3070 ton/hr, 40 tons/hr are lost (9000,III,III-19). Primary efficiency is 9.87E-01.

9025 Air emissions from the crushing and sizing plant consist primarily of fugitive dust or particulates. These emissions are emitted to the atmosphere through the dust collection system in the enclosed crushing plant ventilation system. A wet collection system, cyclone or venturi scrubber, will be placed on the primary crusher and a dry collection device, cyclone or bag house, placed on the secondary and tertiary crushers. Fugitive dust emissions from these devices will not exceed 35 lb/hr (9000,I,I-79). For a yearly plant output of 1.82E+14 Btu, particulate emissions on a 1.00 E+12 Btu basis are 8.40E-01 tons.

9026 Water pollutants in the crushing activity will be negligible. For a 73,600 T/D operation, approximately 325 GPM will be necessary to operate dust control devices. This wastewater is high in suspended solids and probably will contain a dust suppressant such as ARXL sulfonate (9000,I,I-79). The particulate and water mixture will be piped to the spent shale disposal area.

Wastewater from the crushing and retorting plant will be conveyed via pipeline to the spent shale disposal site. It will be used for wetting and irrigation of the spent shale. Excess water from the spent shale pile will be trapped in a holding pond and will be recycled as needed. No water pollutants will be discharged from the plant boundary.

9027 Solid waste from the crushing operation is a result of miscellaneous spillage and losses in the system as well as waste from dust control devices. From footnote 9024, 960 T/D are lost in the crushing operation for a plant processing 73,600 T/D. For a yearly output of 1.82E+14 Btu, solid waste is 1737 tons/10^{12} Btu.

9028 Land impact for the crushing operation handling 73,600 T/D with 3 days storage is assumed to require 15 acres. On a 1.00E+12 Btu basis, land impact is 8.24E-02 acre-yrs.

9029 Wastewater generated in the retorting activity is a result of boiler blowdown, steam generation, wet scrubbing, and process water. Water (2 to 10 gal/ton) is actually produced during retorting as the organic matter is released (9000). For a 50,000 BPSD plant, 0.1 MGD of wastewater is produced (9000). This water contains 40,000 PPM as $CACO_3$(9018). This process water will receive chemical treatment with lime to remove carbonates, most of the ammonia, and some organic material (9018). This wastewater will then be consumed in the spent shale disposal system or used for dust control in the overall plant operation. No effluent will be discharged to the environment (9023) hence water pollutants are 0.00E+00.

9030 Although significant quantities of air pollutants are generated in both the Tosco and Gas Combustion retorts, the tail gas is contained in a closed system and fed to a gas-fired power plant. Air pollutants for burning retort gases will be accounted for under the process of electrical generation. Air emissions for the Tosco and Gas Combustion steps will be 0.00+00 tons/1.00E+12 Btu (9000,9028).

9031 Air emissions for the Gas Combustion electrical generation activity are based on combusting the 100 Btu/SCF (9000) retort gas in a conventional gas-fired power plant. Retort gas composition is given in (9028, 14). Particulate emission is controlled to 0.03 GR/SCF at the retort plant. 184 lb/hr are emitted for a gas rate of 713889 SCF/min. For a heating value of 100 Btu/SCF, particulate emission from the boiler is 2.15E+01 ton/1.00E+12 Btu. SO_x is calculated the same as particulate, however 85 percent SO_x stack gas removal is required to meet the 1.2 lb/1.00E+06 Btu SO_x emission standard. All other emissions are based on rates in (9010,1-9). On a Btu input equivalent of natural gas to retort gas of 100 Btu/1031 Btu = 0.097, the emission rates are as follows

CO 0.40 x 0.097 = 3.88E-02 lb/1.00E+06 SCF
HC 40.0 x 0.097 = 3.88E+00 lb/1.00E+06 SCF
NO_x 390.0 x 0.097 = 3.78E+01 lb/1.00E+06 SCF
ALD 3.00 x 0.097 = 2.91E-01 lb/1.00E+06 SCF

For a 1.00E+10 SCF feed, the air emissions on a 1.00E+12 Btu basis are as follows

CO	1.94E-01 tons
HC	1.94E+01 tons
NO_x	1.89E+02 tons
ALD	1.46E+00 tons

9032 Air emissions for the Tosco electrical generation activity are based on the composition of the retort gas in (9028) and air emissions factors in (9010,1-9). Particulate matter will consist of inorganic ash which will not be combusted in the conventional gas-fired power plant. The heating value of the gas is 815 Btu/SCF (9000,I,I-18) and the output is 32,049 SCFM (9028). On a 1.00E+12 Btu basis the emission of particulates is 2.62E+00 tons. SO_2 is based on the same calculations. SO_2 emission is 5.22E+02 ton/1.00 E+12. The remaining air pollutants are ratioed on an energy basis to those of natural gas. The heating value of Tosco retort gas is 815 Btu/SCF and that of natural gas is 1031 Btu/SCF, hence emission factors are 0.791 of those specified in (9010). For a 1.00E+12 Btu feed of 1.23E+09 SCF, the air emissions are as follows

NO_x	1.90E+02 tons
CO	1.95E-01 tons
HC	1.95E+01 tons
ALD	1.46E+00 tons

9033 Water pollution figures are based on (9015). For a 100,000 BPSD refinery BOD loading is 100 lb/D. The BOD loading for a total plant output of 9.53E+13 Btu/yr (5.80E+06 Btu/BBL) for a 50,000 BPSD refinery is 9.61E-02 tons/1.00E+12 Btu. In a controlled case an API separator is used to remove 25 percent BOD. BOD is 7.21E-02 tons/1.00E+12 Btu (9015).

9034 Air emission factors are based on a storage of 4.73E+03 BBL (10 days) of crude oil in one 5000 BBL floating roof storage tank. HC air emissions are based on 30 lb/day breathing loss (9010) and no working loss. For a storage of 1.00E+12 Btu/yr, the HC emissions are 5.48E+00 tons.

9035 For a 50,000 BPSD plant, 40 acres are required for crude storage. For a yearly output of 9.53E+12 Btu, the land impact is 4.16E-01 acre-yr/1.00E+12 Btu (9000, III).

9036 Primary efficiency for crude oil storage is 100 percent since hydrocarbon emission is considered to be negligible with floating roof storage tanks.

9037 Ancillary energy is based on pumping 472.6 BBL/D (1.00E+12 Btu/yr) 36.5 times a year (10 days storage) both into and out of the storage tank. Assuming a constant total head of 75 feet, a pumping rate of 2000 GPM through an 8 inch steel line, and an efficiency of 75 percent, 50 horsepower is required to pump 12.1 hours. Btu equivalent is 1.54E+06 Btu.

9038 Air pollution is based on diesel engine-pump emissions factors. To pump 172,500 BBL of crude, 3.43E+09 Btu are required using 450 Btu/T-mi (9034,7) and 7.03 lb/gal (9003,588). For distillate heating value of 5.83E+06 Btu/BBL, 2.47E+04 gals are consumed. From (9010,3-7) air emissions are

Particulates	1.61E-01 tons
NO_x	4.56E+00 tons
SO_x	3.34E-01 tons
HC	4.56E-01 tons
CO	2.78E+00 tons
ALD	3.70E-02 tons

9039 To pump 172,500 BBL of crude oil 300 miles (9003,2), 3.43E+09 Btu are required (see footnote 9038). Ancillary energy is 3.43E+09.

9040 Solid waste is based on data in (9000,III-III-23). For every 73,600 tons of oil shale processed, 60,000 ton of spent oil shale is generated. For a 1.00E+12 Btu equivalent oil shale feed of 1.33E+05 tons, 1.08E+05 tons of spent shale is generated.

9041 The retorting plant itself requires about 5 acres (9002,94) for a 50,000 bbl/d operation (72,600 ton shale/d). For a raw shale heating value of 7.53E06 Btu/ton this is equivalent to 2.78E-02 acre yr/10^{12} Btu. Land impact for spent waste shale is considered in the extraction footnotes.

9042 Occupational health statistics are based on data in (9000,I,III-235). Statistics are based on a 10 year period. The fatalities and nonfatalities are 1.37E-03 and 1.44E-01/1.00E12 Btu.

9043 Fixed land impact for the Gas Combustion retort plant is 10 acres for a 50,000 BPSD plant. On a 1.82E+14

Btu/yr input, fixed land impact is 5.50E-02 AC-yr (9002,83). Land impact for spent waste shale is considered in the extraction footnotes.

9044 Primary efficiency for the Gas Combustion retort is 67.3 percent of the standard Fischer assay based on input of 5.47E+11 Btu and output of 3.68E+11 Btu (9000).

9045 Primary efficiency of the Tosco II indirect heating retort is 77.6 percent of standard Fischer assay of the recoverable organic material (9035,IV-11). Based on 4.25E+11 Btu output and 5.47E+11 Btu input (total heat balance of 97.4 percent accounted for).

9046 Ancillary energy is based on data from (9027,41). Power requirements for a 73,600 T/D retorting plant is 27,960 Kw for retorting and 23,610 Kw for solid waste disposal. For a plant input of 1.00E+12 Btu/yr, the power requirement is 7.75E+09 Btu. Real energy is 3 times this or 2.33E+10 Btu.

9047 For a 73,600 T/D underground mine the fixed capital cost including deferred capital and interest during construction is 2.17E+07 dollars (9000,I). For a mine producing 1.82E+14 Btu/yr (24.2E06 tpy) the cost allotted to 1.00E+12 Btu, with a 10 percent fixed charge rate is 7.74E+03 dollars. Operating cost including payroll, supplies, labor, taxes, and insurance is 2.22E+07 dollars. On a 1.00E+12 Btu basis, operating cost equals 7.93E+04 dollars.

9048 For a 147,200 T/D surface mine (3.64E14 Btu/yr), the fixed capital cost including deferred capital and interest during mine development is 4.96E+07 dollars. On a 1.00E+12 basis and at a fixed charge rate of 10 percent, fixed cost is 8.43E+03 dollars (9000,I). Operating cost is 1.78E+07 dollars (9000,I). On a 1.00E+12 Btu basis, operating cost is 3.03E+04 dollars.

9049 For an inclined belt conveyor system handling 3100 T/hr (1.84E+14 Btu/yr) the capital and operating cost are 2.75E+06 and 2.69E+04 dollars/yr. On a 1.00E+12 Btu basis the capital cost is 1.49E+03 and annual operating cost is 1.46E+02 dollars/yr (9033).

9050 Capital cost for truck haulage is based on the cost of 2 road graders, 2 water trucks, and 50 - 100 ton dump trucks. Total capital cost is 4.68E+06 dollars for hauling 1.82E+14 Btu/yr. At a 10 percent fixed charge rate, capital cost = 2.46E+03 $/1.00E+12 (9029,7/26). Operating cost based on (9016,583) using

1.56E+02 $/hr as operating cost to haul 1.82E+14 Btu/yr. Operating cost is 6.74E+03 $/1.00E+12 Btu.

9051 Capital cost for a 73,600 T/D crushing operation (1.82E+14 Btu/yr) is 1.23E+07 dollars (9000,I). At a 10 percent fixed charge rate, fixed cost is 6.67E+03 $/1.00E+12 Btu. Operating cost is based on energy consumption only. For a requirement of 2090 Kw (Footnote 9023), operating cost at 0.015 $/Kw-h is 1.36E+03 $/1.00E+12 Btu.

9052 For an input of 72,600 T/D (1.80E+14 Btu/yr) of oil shale, the capital cost for a retorting plant is 1.16E+08 dollars (9027,37). On a 1.00E+12 Btu/yr basis and a fixed rate of 10 percent, the fixed cost is 6.44E+04 dollars. Operation cost for a 72,600 T/D plant is 1.87E+07 dollars. On a 1.00E+12 Btu/yr basis, the annual operating cost is 1.04E+05 dollars.

9053 Crude oil shale storage cost is based upon a throughput of 172,500 BBL/yr and a 10 day storage capacity. Equivalent tank size would be 4720 BBL. Capital or fixed cost for a 16,200 BBL tank is 124,000 dollars. At fixed charge rate of 10 percent, fixed cost of a 5000 BBL tank is 3.83E+03 $/1.00E+12 Btu (9024,138).

Operating cost is approximately 7 percent (9036,162/168). Operating cost are 2.68E+02 $/1.00E+12 Btu.

9054 For atmospheric distillation, process water pollutants are based on (9015) and an annual BBL feed of 172,500. All wastewater requires primary or physical treatment and secondary treatment in the form of an activated sludge plant. Removal efficiencies for BOD, Phenols, Sulfides, and TDS are 90, 95, 95, 80 percent respectively. Pollutants for distillation are as follows (9015, Table 5):

BOD	1.73E-03 tons/1.00E+12 Btu
Phenol	4.30E+00 tons/1.00E+12 Btu
Sulfide	4.30E-03 tons/1.00E+12 Btu
TDS	6.04E-01 tons/1.00E+12 Btu

For a 1.00E+12 Btu/yr distillation process, power required is 1.91E+10 Btu (9022,32). This includes electrical at 6,90E-01 HP-Hr/BBl and fuel (steam) at 1.07E+05 Btu/BBL. Cooling water is 3.74E+07 gal/1.00E+12 Btu. Wastewater is 10 gal/BBL feed (9020). Miscellaneous HC emissions are based on (9010,9-4) utilizing cooling water, wastewater, and 2/5 of refinery capacity. HC = 2.73E+00 ton/1.00E+12 Btu.

9055 Cooling water for a 1.00E+12 Btu/yr refinery utilizing a hydrogen plant is 1.71E+09 gal/yr. All thermal pollution may be eliminated by utilizing a mechanical draft wet cooling tower.

9056 Air emission for the discreet refinery activities are a result of boiler and process heaters. Sufficient low Btu fuel gas is generated in the retorting steps to supply the refineries' needs. To process 1.00E+12 Btu of shale oil 9.06E+10 Btu of fuel is required and 3.54E+10 Btu of electrical power is required, based on 50 Kw and 40 percent efficiency. To process 172,500 BBL of shale oil requires 82.8 hours and retort gas produced is 1.76E+11 Btu (9028). Since the oil shale upgrading plant will be an integral part of the total shale oil process, the fuel gas produced will be used within a centrally located power plant which will produce all electrical, fuel and steam requirements for the operation. Air pollutants produced by burning fuel gas are accounted for in the power generation process. Except for miscellaneous HC emissions (footnote 9054) all emissions are 0.00E+00.

9057 Capital and operating costs for a 100000 BPSD atmospheric distillation column are 15.97E+06 dollars (Footnote 2043) and 14.2 cents/BBL (9022) respectively. Based on a 1.00E+12 Btu/yr input, equivalent to 473 BPSD, the capital cost is 7.55E+03 dollars. Operating cost is 2.45E+04 dollars/1.00E+12 Btu/yr. Cost of wastewater treatment is attributed to the distillation process. For a wastewater flow of 6144 gal/D for processing 1.00E+12 Btu/yr, wastewater treatment costs are 4.37E+02 dollar capital and 4.75E+02 dollars operating cost. Cost figures are based on footnote 2102 scaled down to handle 6144 gal/D. Total costs for distillation are 9.05E+03 dollars capital and 2.51E+04 dollars operating.

9058 Water pollutants are based on feed of 159000 BBL for the delayed coker. Wastewater treatment efficiencies are stated in footnote 9054. Pollutants are based on (9020). Water pollutants after waste treatment are as follows:

Non-Degradable Organics	2.47E-02 tons
COD	1.02E+00 tons
TDS	4.77-01 tons

9059 Air emissions for process and boiler feed are given in (9031) and (9032). Miscellaneous HC emissions from pipelines, valves, flanges, pump seals are 71 lb/1.00

E+03 BBL refinery. Of the four major processes, the coker throughput is 1/5 of total refinery throughput. HC emissions directly associated with coker are 2.13E+00 ton/1.00E+12 Btu/yr (9010,9-4).

9060 Ancillary energy for the delayed coker is 4.68E+05 Btu/BBL based on a fuel requirement of 4.65E+05 Btu/BBL and electrical requirement of 2.74E+03 Btu/BBL (9022,65). For a 1.00E+12 Btu/yr feed of 159,000 BBL, energy is 7.44E+10 Btu.

9061 Operating cost based on 40 cents/BBL (9022,65). Escalated 60 percent (9037) to reflect 1972 cost on 1.00E+12 Btu/yr basis, operating cost is 6.37E+04 dollars.

9062 Air emissions based solely on HC emissions from cooling water. No other information available. Cooling water required for a 5.55E+06 SCF/D H_2 plant (1.00E+12 Btu/yr gas feed) is 900 gal/MSCF H_2 (9022,183). From (9010) HC emissions are 6 lb/1.00E+06 gallon cooling water. HC emissions are 4.92E+00 tons/1.00E+12 Btu/yr.

9064 Water pollutants are based on (9020,11) for the hydrotreating unit with a 1.00E+12 Btu/yr throughput of 172,500 BBL. All wastewater receives primary and secondary treatment. Removal efficiencies given in footnote (9054). Water pollutants are as follows:

BOD	8.63E-02 tons
COD	1.72E+00 tons
Non-Degradable Organics	7.33E-01 tons
TDS	6.04E-01 tons

9065 Ancillary energy consists of process fuel (steam boiler feed) and electric power. From (9022,94) fuel requirement is 60,000 Btu/BBL and electrical and compression is 5247 Btu/BBL. For a 1.00E+12 Btu feed of 172,500 BBL, energy is 1.13E+10 Btu.

9066 Operating cost for a hydrotreating unit is 28.10 cents/BBL, including a 60 percent escalation cost (9022,94). For a 172,500 BBL feed, operating costs are 4.85E+04 dollars. From (Footnote 2044) a 40,000 BPSD hydrotreating unit costs 3.20E+06 dollars. For a feed of 172,500 BBL equivalent to 10^{12} Btu (521 BPSD), at fixed rate of 10 percent, fixed cost is 4.17E03 dollars.

9067 Ancillary energy for the Tosco power generation activity is 0.00E+00. Tosco II retort gases will produce the fuel and steam within the upgrading facility.

9068 Ancillary energy for the Gas Combustion power generation activity is 0.00+00. Gas produced in retorting will be used to produce steam for the upgrading facility.

9069 Land impact for in situ drilling and restoration is based on the time average land impact for the Colorado, Utah, and Wyoming tracts. Averaging the land impacts gives 1088 acres over a 30 year period. For a crude value of 5.80E+06 Btu/BBL, and output of 50,000 BPSD, 9.53E+13 Btu are produced. On a 1.00E+12 Btu input basis, land impact equals 6.47 ac-yr (9000, I,III-19).

9070 Occupational health statistics are based on (9000,I, III-235). On a 1.00E+12 Btu input basis, deaths are 3.64-03 and injuries are 5.69-01.

9071 Water pollutants for the gas treating facility are zero based on steam stripping of H_2S and NH_3 from sour refinery tailgas. Based on (9038,98) water from treatment facility is of sufficient quality for reuse. Total water effluent is 4.31E+08 gal/yr/ 1.00E+12 Btu/yr input.

9072 Air pollutants from the gas processing activity consist of SO_2 from Claus recovery system. With a 99 percent efficient Claus plant with stack gas cleaning, SO_2 emissions are 4.3E-01 T/D H_2S for a 2.39E+10 Btu/D feed (9000,III). For a 1.00E+12 Btu/yr feed the SO_2 emissions are 33.9 tons/yr. All other emissions are 0.00+00 since gases are recycled to hydrogen plant.

9073 Solid waste for the gas treating facility is 0.00+00 since elemental sulfur and ammonia have a market value (9038,99).

9074 Land impact for a 2.39E+09 Btu/D gas treating facility is assumed to occupy 2.0 acres. On a 1.00E+12 Btu basis, land impacts are 2.55E+00 A-yrs.

9075 Primary efficiency for the gas treating facility is 100 percent based on (9000,III-III-26).

9076 For a gas treating plant for steam stripping, sour water stripping, sulfur recovery (Claus), and ammonia recovery, the capital costs are:

(9038) Gas+Water Stripping	1.35E+06 dollar/40 T/D NH_3
(9039) Claus Plant	3.50E+05 dollar/50 T/D S

To process 143 T/D NH_3 and 43 T/D S (50,000 BPSD plant), using a 0.6 scale factor, total capital cost is 2.90E+06 dollars. The gas feed equivalent is 2.39E+09 Btu/D. Using a 1.00E+12 Btu/yr basis, at 10 percent fixed rate,capital cost is 3.32E+05 dollars. Operating cost is 1.21E+06 dollars/yr (9038) for stripping and 1.00E+05 dollar/yr for Claus recovery (9039), using a 0.6 scale factor. On a 1.00E+12 Btu/yr basis, operating cost is 1.50E+06 dollars/yr. For a 1.00E+12 Btu/yr feed, 49300 ton of NH_3 and 27000 ton of S are produced. At 40 dollars/ton NH_3 and 15 dollars/ton S, annual credit for gas by-product recovery is 1.99E+06 dollars/yr. Operation cost is 0.00E+00 dollars.

9077 Capital cost for a 50,000 BPSD In Situ retorting plant, using recovery plant and compression and initial wells, is 94.7E+06 dollars for processing 1.68E+14Btu/yr input. Annualized capital cost (10 PC FCR) for 1.00E+12 Btu/yr input is 5.64E+04 dollars, plus 1.59E+03 (from Footnote 9079) for a total of 5.78E+04 dollars.

9078 Air emissions for the In Situ retorting activity are based on flaring the low Btu product gas. A 50,000 BPSD plant will produce 1.49E+09 SCF/CD (9000,III,III-29) of low Btu gas, 30 Btu/SCF (9008,15) which is flared after particulate removal to 0.03 gr/SCF. Assuming 90 percent combustion control on CO & HC, emissions are (9028):

Particulates	1.16E+03 ton/yr
SO_x	4.90E+04
NO_x	NA
HC	2.82E+04
CO	2.12E+03

Based on a retorting efficiency of 56.7 percent and a 50,000 bbl/d operation the air pollutants are:

	ton/1.0E12 Btu
Particulates	6.22E+00
SO_x	2.62E+02
CO	1.13E+01
HC	1.51E+02

9079 Water pollutants from In Situ retorting are 0.00E+00 since the water generated is treated with lime, carbon absorption, and ion exchange resins (9018). For a plant producing 50,000 BPSD, 560,000 gal/D are generated (9000,III). After waste treatment the wastewater contains 1890 PPM which is suitable for cooling tower makeup water (9018). For a 1 MGD treatment system the costs are:

Process	Capital	Operating
Lime Treatment	4.61E+04	4.61E+03 (9041)
Ion Exchange	2.10E+06	2.10E+05 (9041)
Carbon Absorption	5.36E+05	6.00E+04 (9040)

Lime and ion exchange operation costs are assumed to be 10 percent of capital cost. For a plant processing 1.00E+12 Btu/yr costs are (retorting efficiency is 56.7 percent):

Capital	1.59E+03 dollars
Operation	1.64E+03 dollars

9081 Miscellaneous HC emissions based on process drains, cooling water, pipes, valves, flanges, and pumps (9010). For a hydrotreating unit processing 172,500 BPSD, cooling water is 3.86E+07 gal, wastewater is 1 gal/BBL, and hydrotreating throughput is 2/5 of total refinery capacity. For a 1.00E+12 Btu/yr refinery misc. HC emissions are 2.59E+00 tons.

9082 Waste water will be treated and recycled for use within the plant boundaries. It is assumed that no water pollutants will be discharged (9000,III,IV-80).

9083 Air pollutants for processing 1.00E+12 Btu/yr occur in the retorting, distillation, delayed coking, H_2 manufacture, hydrotreating, gas treating, and power generation activities. For each process pollutant on a 1.00E+12 Btu/yr basis see individual processes and respective footnotes and references. To process 1.00E+12 Btu/yr, the respective feeds and pollutants are:

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Process	Feed	Part.	NO_x	SO_x	HC	CO	ALD
Retort	133000T/Y						
Dist.	97900BPY				1.71		
Coking	48950BPY				0.62		
H_2 Manu.	779000SCF/YR				2.10		
Hydrot.	89016BPY				1.32		
Gas Trt.	4.37E+10BTU/YR			1.5			
Storage	91486 BPY				2.91		
Power	1.88E+11BTU/YR	4.04	35.5	29.1	3.65	.0365	.275
Total		4.04	35.5	30.6	12.3	.0365	.275

Total pollutants to process 1.00E+12 Btu are 8.28E +01 tons.

9084 Air pollutants for processing 1.00E+12 Btu/yr occur in the retorting, distillation, delayed coking, H_2 manufacture, hydrotreating, gas treating, and power generation activities. For each process pollutant on a 1.00E+12 Btu/yr basis see the individual processes and their respective footnotes and references. To process 1.00E+12 Btu/yr of oil shale, the unit feed and pollutants are:

Process	Feed	Part.	NO_x	SO_x	HC	CO	ALD
Retort	133000T/Y						
Dist.	122000BPY				2.16		
Coking	61000BPY				0.777		
H_2 Manu.	972000SCF/YR				2.63		
Hydrot.	111000BPY				1.66		
Gas Trt.	5.48E+10BTU/YR			1.86			
Storage	114500BPY				3.64		
Power	6.83E+10BTU/YR	0.178	12.9	35.5	1.33	0.0133	0.099
Total		0.178	12.9	37.4	12.2	0.0133	0.099

Total air pollutants for processing 1.00E+12 Btu are 6.28E+01 tons.

9085 Air pollutants for processing 1.00E+12 Btu/yr occur in the retorting, distillation, delayed coking, H_2 manufacturing, hydrotreating, gas treating, and power generation activities. For the pollutants for each process, on a 1.00E+12 Btu/yr basis, see the individual processes and the respective footnotes and references. To process 1.00E+12 Btu/yr of oil shale, the unit feed and pollutants are:

Process	Feed	Part	NO_x	SO_x	HC	CO	ALD
Retort	172400BPY	6.22		262.0	151.0	11.3	
Dist.	97900BPY				1.71		
Coking	48950BPY				0.62		
H_2 Manu.	779000SCF/YR				2.10		
Hydrot.	89016BPY				1.32		
Gas Trt.	4.37E+10BTU/YR			1.5			
Storage	91486BPY				2.91		
Steam	3.90+10 BTU/YR	.286	7.5	.011	.76	.007	.134
Total		6.51	7.5	263.5	160.4	11.3	.134

Total pollutants for processing 1.00E+12 Btu are 4.49E+02 tons.

9086 Primary efficiency for In Situ oil shale retorting is assumed to be 56.7 percent. For nuclear fracturing and retorting, efficiency may be as high as 70 percent (9001, 12-9). For an input of 172,400 BBL/yr (1.00E+12 Btu/yr), 97900 BBL/yr are produced.

9087 Land impact for processing 1.00E+12 Btu utilizing the gas combustion method is based on 320 acres fixed land for surface facilities and offsites from (9000, I-III-12) for a 72,700 TPD shale oil operation (50,000 bbl/d).

9088 Land impact for processing 1.00E+12 Btu utilizing the Tosco II process is based on 320 acres fixed land for surface facilties and offsites from (9000,I-III-12) for a 72,700 TPD shale oil operation (50,000 bbl/d).

9089 Land impacts for conventional In Situ processing of oil shale is based on 230 acres fixed land for surface facilities and offsites from (9000,I-III-12) for a 50,000 bbl/d operation plus that land required in the retorting process from footnote 9069 for a total of 7.84 acre yr/1.0E12 Btu.

9090 Occupational health statistics are based on retorting and power generation only. No other information is available. For individual processes, refer to the respective footnotes and references. To process 1.00E+12 Btu/yr the impacts are:

Process	Deaths	Injuries	Man-Days
Gas Combustion	1.48E-03	1.55E-01	4.44E-01
Tosco II	1.41E-03	1.48E-01	1.49E-01
In Situ	3.66E-03	5.71E-01	9.20E-02

FTN. 9091-9098

9091 Primary efficiency of the delayed coking process is 89.7 percent based on an input of 1.55E+11 Btu/D (hydrogen and product) and an output of 1.39E+11 Btu/D (fuel gas and product) (9000,III).

9092 Primary efficiency of the hydrotreating process is 96.8 percent based on an input of 3.13E+11 Btu/D (hydrogen and product) and an output of 3.02E+11 Btu/D (fuel gas and product) (9000,III).

9093 Primary efficiency is based on the assumption that 53500 B/D of crude oil will be produced by retorting 72600 T/D of 7.53E+06 Btu/T oil shale. Recovery efficiency is 56.7 percent due to migration and drift of underground shale oil.

9094 Waste water will be treated and recycled for use within the plant boundaries. It is assumed that no water pollutants will be discharged (9000,III-IV-80).

9095 Overall primary efficiency is based on an input of 1.33E+05 ton/yr (1.00E+12 Btu/yr) and an output of 91486 BBL/yr (5.31E+11 Btu/yr) (9000,III).

9096 Overall efficiency of a Tosco II oil shale plant is based on an input of 133000 ton/yr (1.00E+12 Btu/yr) and an output of 114,500 BBL/yr (6.67E+11 Btu/yr).

9097 Ancillary energy for a Gas Combustion oil shale processing plant is 0.00E+00 Btu/yr. A plant processing 72,600 T/D requires 50 MW (9031), hence a plant processing 133,000 T/yr requires 250 Kw. Total electrical energy for the plant will require an input of 2.09E+10 Btu/yr and a fuel/steam requirement of 3.90E+10 Btu/yr (9022). Total energy required to process 1.00E+12 Btu/yr (133,000 T/yr) is 6.23E+10 Btu/yr. Fuel gas produced in retorting is 1.11E+11 Btu/yr (9000,III).

9098 Ancillary energy to process 133,000 T/yr (1.00E+12 Btu/yr) utilizing the Tosco II method is 0.00E+00 Btu/yr. Electrical requirements for retorting and upgrading will be 250 Kw-hr/h (1.97E+10 Btu/yr) and 1.2E+09 Btu/yr (9022) respectively. Fuel/steam requirement for upgrading is 4.83E+10 Btu/yr. Total energy required is 6.92E+10 Btu/yr. Fuel gas from retorting as a result of processing 133,000 T/yr is equal to 6.92E+10 Btu/yr (9028), hence a Tosco II plant will be self-sufficient.

9099 Ancillary energy for the In Situ oil shale processing plant is 5.99E+10 Btu/yr. Electric power required to process 133,000 T/D by in situ retorting, and upgrading the resulting 97,900 B/D, is 2.09E+10 Btu/yr. This assumes total plant electrical requirement is the same as the equivalent gas combustion plant, 250 Kw-hr/h. Fuel/steam for the upgrading facility requires 3.90E+10 Btu/yr (9022). Total energy required is 5.99E+10 Btu/yr. Gas produced for in situ retorting (29.2 Btu/SCF) (9028) is too low in heating value for economic use hence it is flared. All energy will be purchased, 2.09 E+10 Btu/yr electrical energy and 3.90E+10 Btu/yr fuel gas. Natural gas will be used to fire a heavy industrial boiler to produce steam for upgrading.

9100 Efficiency of a heavy industrial boiler is 88.0 percent (9041,19-6).

9101 Total annual capital and operating cost for processing 133000 T/yr (1.00E+12 Btu/yr) utilizing the gas combustion retorting method is given below. For references and footnotes, refer to individual processes. Cost figures are in dollars.

Process	Feed	Annualized Capital Cost	Operating Costs	Total Costs
Retorting	1.33E+05T/Y	5.82E+04	9.38E+04	1.52E+05
Distillation	9.79E+04BPY	4.28E+03	1.40E+05	1.44E+05
D. Coking	4.90E+04BPY	1.10E+04	1.95E+04	3.05E+04
H_2 Manuf.	7.79E+05SCF/YR	1.04E+04	5.19E+04	6.23E+04
Hydrotrmt	8.90E+04BPY	1.95E+04	2.50E+04	4.45E+04
Gas Trmt	4.37E+10BTU/YR	1.28E+04	0.00E+00	1.28E+04
Storage	9.15E+04BPY	2.02E+03	1.41E+03	3.43E+03
Power Plt	1.11E+11BTU/YR	---	---	3.96E+04
		1.18E+05	3.32E+05	4.89E+05

9102 Total annual capital and operating cost for processing 133000 T/Y (1.00E+12 Btu/yr) utilizing the Tosco II method is given below. For references and footnotes see individual activities.

Process	Feed	Annualized Capital Cost	Operating Costs	Total Costs
Retorting	1.33E+05T/Y	---	---	---
Distillation	1.22E+05BPY	5.33E+03	1.75E+05	1.80E+05
D. Coking	6.10E+04BPY	1.37E+04	2.44E+04	3.81E+04
H_2 Manuf.	9.72E+05SCF/YR	1.30E+04	6.49E+04	7.79E+04
Hydrotrmt	1.11E+05BPY	2.43E+04	3.13E+04	5.56E+04
Gas Trmt	5.48E+10BTU/YR	1.61E+04	7.58E+04	9.19E+04
Storage	1.15E+05BPY	2.53E+03	1.76E+03	4.29E+03
Power Plt	6.91E+10BTU/YR	---	---	3.96E+04
		7.50E+04	3.73E+05	4.87E+05

9103 Total annual capital and operating cost for an In Situ oil shale operation processing 133000 T/Y (56.7 percent efficiency) or 97900 B/Y are given below. For individual references and footnotes see the respective individual activities.

Process	Feed	Annualized Capital Cost	Operating Costs	Total Costs
Retorting	1.33E+05T/Y	5.12E+04	---	5.12E+04
Distillation	9.79E+04BPY	4.28E+03	1.40E+05	1.44E+05
D. Coking	4.90E+04BPY	1.10E+04	1.95E+04	3.05E+04
H_2 Manuf.	7.79E+05SCF/YR	1.04E+04	5.19E+04	6.23E+04
Hydrotrmt	8.90E+04BPY	1.95E+04	2.50E+04	4.45E+04
Gas Trmt	4.37E+10BTU/YR	1.28E+03	6.06E+04	7.34E+04
Storage	9.15E+04BPY	2.02E+03	1.41E+03	3.43E+03
Steam Plant	3.90E+10BTU/YR	---	---	---
		1.11E+05	2.98E+05	4.09E+05

9104 Disasters (a single accident resulting in 5 or more deaths) occur frequently in underground mines. In the past 40 years only 6 calendar years went without a disaster occurring.

9105 Primary efficiency is defined as 1 minus the fraction of the primary fuel input attributable to physical losses minus the fraction of the primary fuel input used in the process as fuel and/or steam. By equation, the primary efficiency equals (1-(Y/1.0E12)-(Z/1.0E12)) x 100P, where Z is the Btu of physical losses and Y is the Btu of input feed used as fuel and/or steam. All of the refinery processes would use fuel gas as the primary fuel; thus Y equals 0 and the primary efficiency approaches 1 except for physical losses such as those due to evaporation and wastewater contaminants. This procedure results in a high ancillary fuel requirement. It can be shown that the overall process efficiency will be the same as that if Y were large and the ancillary demand low. All efficiencies are on a Btu basis. It was further assumed that oil lost to wastewater would have the same heat content as crude oil and that hydrocarbon losses to the atmosphere would have a heating value of 200 Btu/lb.

VI. FLUIDIZED BED BOILER COMBUSTION

A. Introduction

The environmental impacts, efficiencies and costs of Fluidized Bed Boiler Combustion of coal in a power plant cycle are given in Table 4 of this report. All line entries in the table are "processes" according to the nomenclature adopted and defined on page II-1. The fluidized bed process using coal is intended to be integrated with the more complete set of coal data on extraction, conversion, transportation, etc. already published in Volume I of this report. Fluidized bed combustion is part of the power plant conversion activity.

Entries in the table are based on an energy input of 10^{12} Btu/yr into each power plant utilizing the fluidized combustion process. All of the cost data shown in Table 4 is based on a 75 percent plant load factor, or 274 operating days/yr. The values presented in this table are based on data accumulated during the early months of 1974. Entries assume controlled emissions in all cases. Entries in the table reflect the combustion of a high sulfur central region coal, a medium sulfur Northern Appalachian coal and a low sulfur Northwestern coal in each of two proposed fluidized bed boiler power plant systems. These systems are:

(1) The 635 Mw Westinghouse Pressurized Fluidized Bed Boiler Power Plant, Westinghouse Research Laboratories, Pittsburgh, PA.

(2) The 30 Mw Pope, Evans and Robbins Atmospheric Pressure Fluidized Bed Boiler Power Plant, Pope, Evans and Robbins, Inc., Alexandria, VA.

The concept of fluidized bed combustion has long been known and used in the petroleum industry. Its advantages for coal combustion have begun to be explored for several reasons. The basic justification for developing fluidized bed boilers is their ability to burn high sulfur coal with low SO_2 and NO_x emissions. Further, the fluid bed's inherently high heat release and heat transfer coefficients can drastically reduce the boiler's size, weight, and cost.

Instead of burning coal in a large furnace where only the furnace envelope absorbs heat, crushed coal is burned in a fluidized bed composed of 1/16 in. - 1/8 in. particles of limestone or dolomite which absorbs the sulfur in the coal to form $CaSO_4$. The heat transfer surfaces or boiler tubes can be embedded in the fluidized bed directly because combustion takes place at temperatures ($\sim 1500^{o}F$) which will not damage the tubes. Heat release rates of 200,000 Btu/ft^3-hr have been attained in fluidized bed boilers as compared to 17,000 Btu/ft^3-hr in conventional boilers. High heat release results in the fluidized bed boiler being more compact than a conventional boiler. Because of this, fluidized bed boilers can be built as factory-assembled, packaged units, shipped to site and arrayed as required. This reduces construction time for a new power plant considerably.

The Westinghouse Pressurized Fluidized Bed Boiler, developed for EPA, consists of four modules (Figure 21). Each module includes four primary fluidized bed combustors stacked vertically. Each module also contains a separate fluidized carbon burn-up cell to complete combustion of carbon elutriated from the primary beds. Almost all the boiler heat transfer surface is immersed in the beds.

The beds are pressurized to 10 atmospheres and fluidization is carried out with air at 8-15 fps. After particulate removal, the high pressure, high temperature gases leaving the combustor pass directly into a gas turbine which expands them to atmospheric pressure. Stack gas coolers recover sensible heat to preheat feedwater.

Coal combustion takes place in a dolomite bed to absorb sulfur. The spent dolomite is regenerated in a two-step reduction/steam-CO_2 oxidation reaction, and recycled. The H_2S released during this process is recovered as sulfur. Make-up dolomite is fed with the coal.

The feedwater is preheated in the water walls enclosing the beds and then saturated steam is generated in the boiler tubes submersed in the fluidized bed. Saturated steam then flows through superheater beds to the high pressure steam turbine. The steam returns to the reheat bed between the high and low pressure steam turbines.

The proposed Pope, Evans and Robbins Atmospheric Pressure Fluidized Bed Boiler Power Plant, developed for OCR, consists of a single-bed-level arrangement of four open-space modular cells augmented by an open row of "Seibel" water-containing tubes extending out from the integral wall dividers (Figure 22). Fluidization of the bed is carried out at 12-14 fps. The integral 2000°F bed limestone regenerator and carbon burn-up cells (CBC) are water-cooled. Offgases from both boiler and auxiliary cells are cooled to 715°F by an integral economizer section. Boiler and regenerator cell flyash are fed to the CBC. Sulfated limestone is pneumatically transported from the front of the boiler bed to the regeneration cell where, under high temperature reducing conditions, $CaSO_4$ is converted to CaO and SO_2 from which sulfur is recovered. CaO is returned to the main boiler bed. One percent sodium chloride is added to the boiler along with the make-up limestone. This enhances sulfur absorption by the limestone and reduces carbon losses.

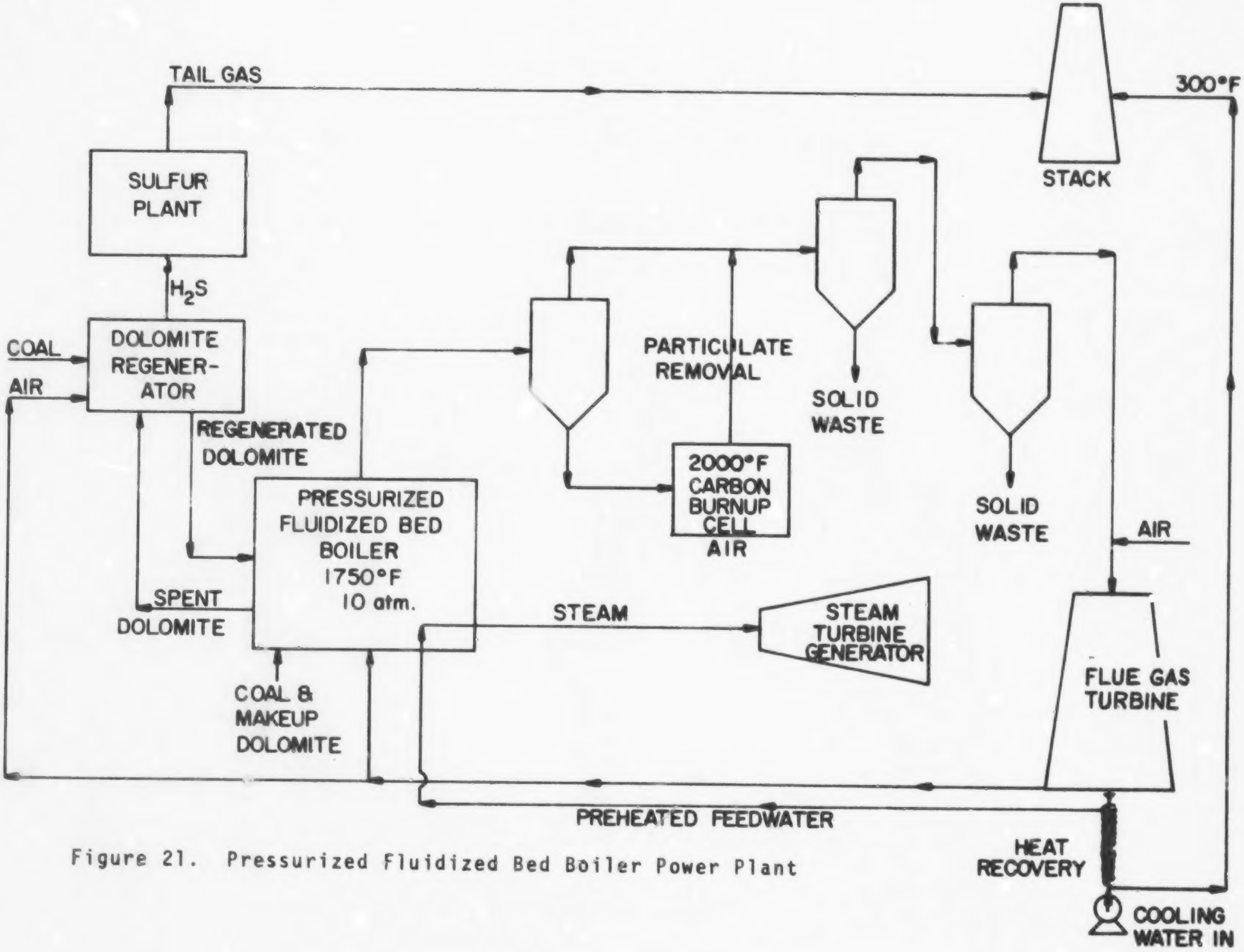
TAIL GAS
STACK
300°F
SULFUR PLANT
H_2S
COAL
AIR
DOLOMITE REGENER-ATOR
REGENERATED DOLOMITE
PRESSURIZED FLUIDIZED BED BOILER 1750°F 10 atm.
SPENT DOLOMITE
COAL & MAKEUP DOLOMITE
PARTICULATE REMOVAL
2000°F CARBON BURNUP CELL
AIR
SOLID WASTE
SOLID WASTE
AIR
STEAM
STEAM TURBINE GENERATOR
FLUE GAS TURBINE
PREHEATED FEEDWATER
HEAT RECOVERY
COOLING WATER IN

Figure 21. Pressurized Fluidized Bed Boiler Power Plant

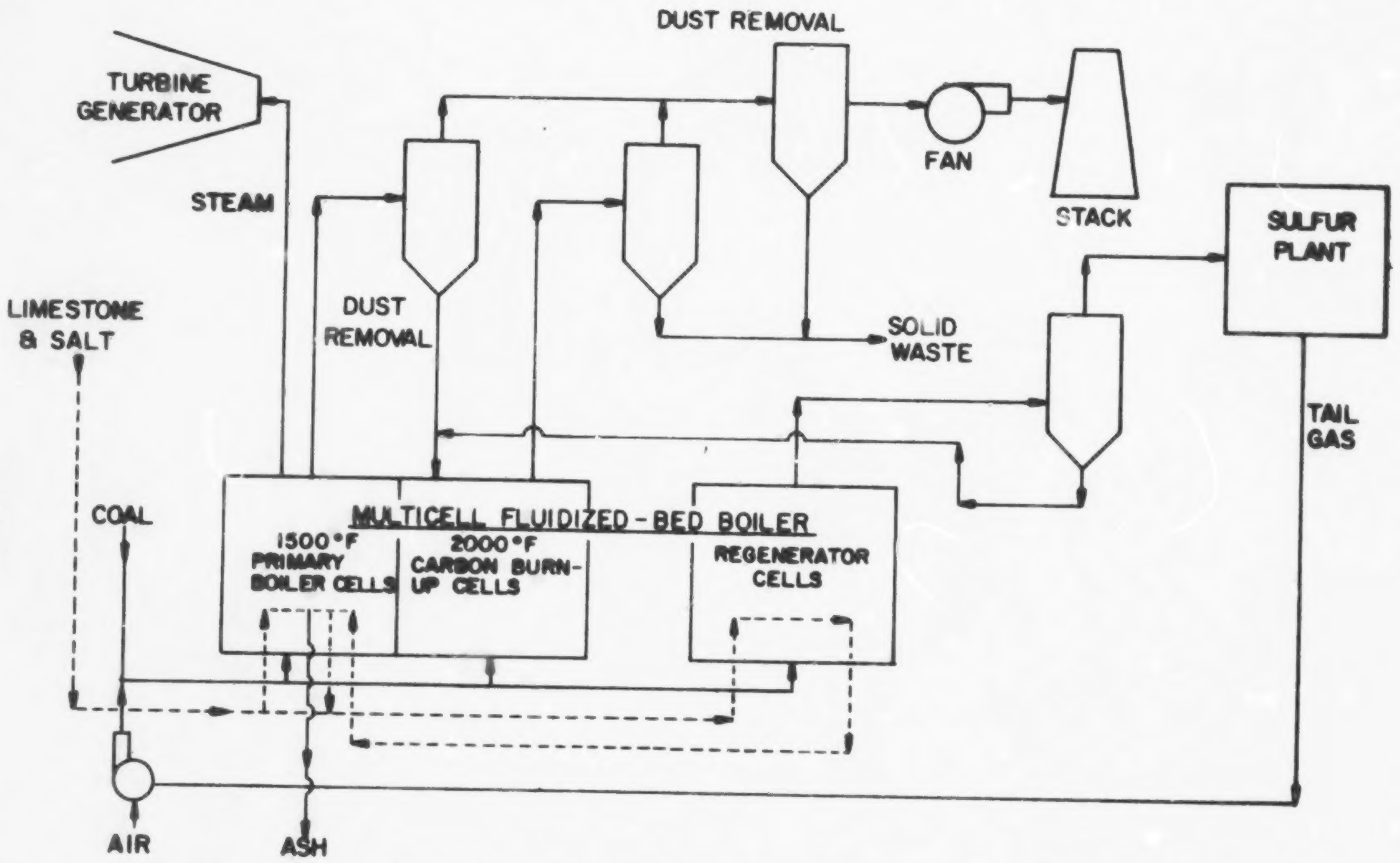
DUST REMOVAL
TURBINE GENERATOR
STEAM
FAN
STACK
SULFUR PLANT
LIMESTONE & SALT
DUST REMOVAL
SOLID WASTE
TAIL GAS
COAL
MULTICELL FLUIDIZED-BED BOILER
1500°F PRIMARY BOILER CELLS
2000°F CARBON BURN-UP CELLS
REGENERATOR CELLS
AIR
ASH

Figure 22. Atmospheric Pressure Fluidized Bed Boiler Power Plant

B. IMPACT DATA TABLE AND FOOTNOTES

CONTROLLED CASE

FUEL	REGION
COAL	AS INDICATED

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX COL 12)												AIR		
					DISSOLVED SOLIDS												
ROW	MNE-MON	PROCESS	ACIDS	BASES	PO_4	NO_3	OTHER	TOTAL (DS)	SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	SO_x
1		CENTRAL REGION															
2	PRFBB	PRESS. FLUIDIZED BED COMBUSTION	0.00+00 3 9200	0.00+00 3 9200	0999	0999	1.82+01 4 9200	1.82+01 4	0.00+00 3 9200	3.02-03 3 9200	1.82+01 4	0999	0999	0.00+00 1 9201	9.29+00 1 9202	6.73+01 1 9202	4.41+02 1
3		POWER PLANT CYCLE															
4	ATFBB	ATMOSPHERIC FLUIDIZED BED	.00+00 3 9209	0.00+00 3 9209	0999	0999	1.82+01 4 9209	1.82+01 4	0.00+00 3 9209	3.02-03 3 9209	1.82+01 4	0999	0999	0.00+00 1 9201	1.13+01 1 9211	7.00+01 1 9211	1.78+02 1
5		COMBUSTION POWER PLANT CYCLE															
6		NORTHERN APPALACHIA REGION															
7	PRFBB	PRESSURIZED FLUIDIZED BED	0.00+00 3 9200	0.00+00 3 9200	0999	0999	1.82+01 4 9200	1.82+01 2	0.00+00 3 9200	3.02-03 3 9200	1.82+01 4	0999	0999	0.00+00 1 9201	1.23+01 2 9221	6.73+01 1 9221	2.10+02 2
8		COMBUSTION POWER PLANT CYCLE															
9	ATFBB	ATMOSPHERIC FLUIDIZED BED	0.00+00 3 9209	0.00+00 3 9209	0999	0999	1.82+01 4 9209	1.82+01 4	0.00+00 3 9209	3.02-03 3 9209	1.82+01 4	0999	0999	0.00+00 1 9201	8.52+00 2 9226	7.00+01 1 9226	1.57+02 1
10		COMBUSTION POWER PLANT CYCLE															
11		NORTHWEST REGION															
12	PRFBB	PRESSURIZED FLUIDIZED BED	0.00+00 3 9200	0.00+00 3 9200	0999	0999	1.82+01 4 9200	1.82+01 4	0.00+00 3 9200	3.02-03 3 9200	1.82+01 4	0999	0999	0.00+00 1 9201	9.70+00 2 9216	6.73+01 1 9216	7.18+01 3
13		COMBUSTION POWER PLANT CYCLE															
14	ATFBB	ATMOSPHERIC FLUIDIZED BED	0.00+00 3 9209	0.00+00 3 9209	0999	0999	1.82+01 4 9209	1.82+01 4	0.00+00 3 9209	3.02-03 3 9209	1.82+01 4	0999	0999	0.00+00 1 9201	5.31+00 2 9230	7.00+01 1 9230	5.68+01 1
15		COMBUSTION POWER PLANT CYCLE															
16		NATIONAL REGION															
17	PRFBB	PRESSURIZED FLUIDIZED BED	0.00+00 3 9234	0.00+00 3 9234	0999	0999	1.82+01 4 9234	1.82+01 4	0.00+00 3 9234	3.02-03 3 9234	1.82+01 4	0999	0999	0.00+00 1 9234	1.04+01 2 9234	6.73+01 1 9234	2.41+02 1
18		COMBUSTION POWER PLANT CYCLE															
19	ATFBB	ATMOSPHERIC FLUIDIZED BED	0.00+00 3 9234	0.00+00 3 9234	0999	0999	1.82+01 4 9234	1.82+01 4	0.00+00 3 9234	3.02-03 3 9234	1.82+01 4	0999	0999	0.00+00 1 9234	8.38+00 2 9234	7.00+01 1 9234	2.01+02 1
20		COMBUSTION POWER PLANT CYCLE															
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12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
RMAL /10^{12}BTU	PARTIC-ULATES	NO_x	SO_x	HYDRO-CARBONS	CO	ALDEHYDES TC	TOTAL	SOLIDS TONS / 10^{12}BTU	LAND (ACRE-YR / 10^{12} BTU)	DEATHS 10^{12} BTU	INJURIES 10^{12} BTU	MAN-DAYS LOST/10^{12}BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY (BTU/10^{12}BTU)	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
1 9201	9.28+00 1 9202	6.73+01 1 9202	4.81+02 1 9202	0.00+00 1 9201	0.00+00 1 9203	0.00+00 1 9203	5.18+02 1	6.76+03 2 9204	4.15+00 2 9205	0999	0999	0999	0999	3.55-01 1 9206	0.00+00 2 0997	3.66+05 3 9207	1.26+05 3 9207	4.92+06 3	2
																			3
1 9201	1.13+01 1 9211	7.00+01 1 9211	3.78+02 1 9211	2.42+02 2 9211	2.50+00 2 9211	0.00+00 1 0997	7.04+02 2	6.99+03 2 9212	4.28+00 3 9213	0999	0999	0999	0999	3.68-01 1 9214	0.00+00 2 0997	2.35+05 2 9215	1.34+05 3 9215	3.69+05 3	4
																			5
																			6
1 9201	1.13+01 2 9221	6.73+01 1 9221	2.10+02 2 9221	0.00+00 1 9203	0.00+00 1 9203	0.00+00 1 9203	2.90+02 1	5.78+03 2 9222	3.78 [illegible] 2 9223	0999	0999	0999	0999	3.55-01 1 9206	0.00+00 2 0997	3.66+05 3 9207	1.19+05 3 9224	4.85+05 3	7
																			8
1 9201	8.52+00 2 9226	7.00+01 1 9226	1.67+02 1 9226	2.42+02 2 9226	2.50+00 2 9226	0.00+00 1 0997	4.90+02 2	5.88+03 2 9227	3.82+00 3 9228	0999	0999	0999	0999	3.68-01 1 9214	0.00+00 2 0997	2.35+05 2 9215	1.23+05 3 9229	3.58+05 3	9
																			10
																			11
1 9201	9.70+00 2 9216	6.73+01 1 9216	7.18+01 1 9216	0.00+00 1 9203	0.00+00 1 9203	0.00+00 1 9203	1.49+02 1	3.95+03 2 9217	3.09+00 2 9218	0999	0999	0999	0999	3.55-01 1 9206	0.00+00 2 0997	3.66+05 3 9207	1.15+05 3 9219	4.81+05 3	12
																			13
1 9201	5.31+00 2 9230	7.00+01 1 9230	5.68+01 1 9230	2.42+02 2 9230	2.50+00 2 9230	0.00+00 1 0997	3.76+02 2	3.99+03 2 9231	3.10+00 2 9232	0999	0999	0999	0999	3.68-01 1 9214	0.00+00 2 0997	2.35+05 2 9215	1.16+05 3 9233	3.51+05 3	14
																			15
																			16
1 9234	7.[illegible]+01 2 9234	6.73+01 1 9234	2.41+02 1 9234	0.00+00 1 9234	0.00+00 1 9234	0.00+00 1 9234	3.19+02 1	5.50+03 2 9234	1.69+00 2 9234	0999	0999	0999	0999	3.55-01 1 9234	0.00+00 2 0997	3.66+05 3 9234	1.20+05 3 9234	4.86+05 3	17
																			18
1 9234	8.38+00 2 9234	7.00+01 1 9234	2.01+02 1 9234	2.42+02 2 9234	2.50+00 2 9234	0.00+00 2 9234	5.24+02 2	5.62+03 2 9234	3.73+00 2 9234	0999	0999	0999	0999	3.68-01 1 9234	0.00+00 2 0997	2.35+05 2 9234	1.24+05 3 9234	3.59+05 3	19
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TABLE 4. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL FLUIDIZED BED BOILER COMBUSTION POWER PLANTS

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Footnotes for Table 4

9200 Entries in the table are based on an energy input to each process of 1.00E12 Btu/yr. Water pollutants are assumed to be the same as those from a controlled conventional coal-fired boiler since many of the unit process operations are the same. Thus from footnote 1908 organic emissions are 3.02-03 ton/10^{12} Btu and dissolved solids amount to 18.2 ton/10^{12} Btu while increase in suspended solids is negligible. Capital cost for control is estimated at $1/Kw and operating cost is taken at .05 mills/Kw-hr (9221, 233, 234).

9201 Thermal pollution is controlled by use of a mechanical draft wet cooling tower system at a cost of $10/Kw (9221). Cooling tower operating cost is estimated at 0.05 mills/Kw-hr (9209,III-3). First generation fluidized bed boiler plants will produce 10 percent less waste heat than conventional plants, and second generation plants will produce 25 percent less waste heat (9200,274).

9202 Air emissions for the 635 Mw pressurized fluidized bed boiler plant which are given in (9200,272) are based on a plant with a heat rate of 8892 Btu/Kw-hr and a full load plant efficiency of 38.4 percent (9200,272). However, by this report's definition of efficiency (see explanatory section prefacing report), the additional coal used in the dolomite regeneration system must also be included as part of the primary energy input. From (9200,274) fuel for regeneration amounts to 0.31 mills/Kw-hr. Dividing by total fuel costs of 4.35 mills/Kw-hr, 7.12 percent is the fraction of total coal used for the regeneration system. On this premise, the heat rate of the plant then becomes 8892+(0.0712x8892) Btu/Kw-hr or 9525 Btu/Kw-hr, and plant efficiency is thus reduced to 35.8 percent. From (9221,234,446) electrical energy requirements for a 500 Mwe plant amount to 5.022 Mwe or 1% for thermal and chemical water pollution control. Hence the overall plant efficiency is reduced to 35.5 percent. The plant operates at 10 atmospheres pressure with bed temperatures of 1300 to 1750 degrees F. Air emissions are based on the fluidization of a 4.3 percent sulfur Central region coal with dolomite absorbent added to that portion of it in the boiler (93 percent) to give a calcium/sulfur ratio of 6/1. The coal has a net heating value of 12500 Btu/lb and an ash content of 8.5 percent. Air emissions given in the table are based on those given in (9200,272), but adjusted as stated above to reflect the additional coal considered as primary energy input. Thus for a 1.0E12 Btu input, 7.12 percent or 7.12E10 Btu goes to the regenerator and 92.88 percent or 0.93E12 Btu is combusted in the boiler. Particulate emissions are derived from the boiler plant (includes boiler and coal drying but not fugitive dust)-0.0186 to 0.149 lb/1.0E06 Btu. The upper limit of this range is

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for the case where no particulate control on the stack is used in addition to the four 90 percent efficient cyclone collectors and two 97 percent efficient Tornado collectors presently planned for each boiler module (9200,271). (Each module includes 4 primary fluidized bed combustors—one bed for the pre-evaporator, 2 beds for the superheater and one bed for the reheater). The lower end of the particulate range,which is used in the table,assumes one additional 90 percent efficient secondary cyclone. NO_x emissions derive from the boiler plant and range from 0.065-0.204 lb/1.0E06 Btu. Under combustion conditions of 1500 degrees F, a sulfated bed (which promotes reduction of NO_x (9206,18)),limitation of excess air to the bed and maintenance of high pressure, NO_x emissions can be controlled within this range. This is well below the EPA emission standard of 0.7 lb NO_2/ 1.0E06 Btu (9207,19). SO_x emissions derive from the boiler plant (0.65 lb/1.0E06 Btu), dolomite regeneration (0.093 lb/1.0E06 Btu),and sulfur recovery (0.093-0.186 lb/1.0E06 Btu). Total SO_x emissions are 0.836-0.929 lb/ 1.0E06 Btu, well below the EPA emission standard of 1.2 lb/1.0E06 Btu. Emissions shown in the table are, except for particulates, calculated from the average between the high and low values for each pollutant as given above.

Air emissions summary for a 635 Mw pressurized fluidized bed boiler in tons/1.0E12 Btu

Particulates	9.3
Sulfur Oxides (as SO_2)	441.2
Nitrogen Oxides	67.3
Total	517.8

9203 Under the design conditions of operation given in (9200, 269),i.e. 10 Atm Pressure, 10 percent excess air in the primary beds and 30 percent excess air in the carbon burn-up cell, it is assumed that there are no gaseous carbon compounds produced which are not fully oxidized to CO_2(9205).

9204 Footnote 9202 states that the coal contains 8.5 percent ash which amounts to 3400 tons/1.0E12 Btu. Ref. (9204, 147) states that 10 percent of the sorbent is rejected during regeneration and 3 percent is elutriated from the bed. From the material balance diagram shown in Ref. (9204,H-100) it can be seen that the dolomite make-up rate is 10.6 percent of the dolomite in the boiler. Thus, this is the amount discarded to solid waste and amounts to 3354.82 tons dolomite/1.0E12 Btu. Therefore total solid waste (subtracting particulates) is 6755.3 tons/1.0E12 Btu. Sulfur recovered not included.

9205 From the site plan of the 635 Mw plant shown in Ref. (9207,105) the fixed land impact for the plant, including coal storage and ash and dolomite storage, is 59.8 acres. Using the plant heat rate calculated in footnote 9202 of 9621 Btu/Kw-hr, and a 75 percent load factor, Btu's/yr going into the plant were calculated as 40.1E12 Btu. Scaling down linearly to 1.0E12 Btu/yr input, fixed land impact was determined as 1.49 acres. From (9222, 45) cooling towers are estimated to occupy 10 acres for a 1000 Mwe plant or .130 ac-yr/10^{12} Btu. Hence the total fixed land use is 1.62 ac-yr/10^{12} Btu. Based on 6755.3 tons solid waste with an average density of 60.45 lb/CF (see footnote 9213), and waste banks 30 ft high, the annual incremental land use due to solid waste is 0.171 acres. Time averaged over a 30 yr plant lifetime and added to fixed land gives a total land impact of 4.19 acre-yr/1.0E12 Btu.

9206 The literature value of efficiency, 38.4 percent (see footnote 9202 for efficiency value adjusted for coal input into regenerator) assumes a back pressure of 1-1/2 inches mercury, a boiler efficiency of 88.6 percent and pressure losses in the gas turbine combustor loop of 7.5 percent.

9207 Fixed costs were determined from (9200,273) for a regenerative pressurized fluidized bed boiler power cycle of 635 MWe producing 4.17E09 Kw-hr/yr at a load factor of 75 percent and a heat rate of 9621 Btu/Kw-hr (see footnote 9202). No adjustment has been made in the dollars/Kw value to reflect the use of a 75 percent load factor instead of the 70 percent used in (9200,273). Construction costs escalated to $220.36/Kw from (9208,162). Total fixed cost does not include the cost of coal (49 cents/million Btu (9200,273)), but does include water pollution control costs (see footnote 9200 & 9201). Total fixed cost is thus 3.49E+06 dollars + 1.74E+05 dollars per 1.0E12 Btu. At a fixed charge rate of 10 percent, annual fixed cost is 3.66E05 dollars/1.0E12 Btu. Operating costs of 0.98 mills/Kw-hr are from (9200, 274) updated to 1972 prices (9208,162). Operating costs also include cost of water pollution control at 0.1 mills/Kw-hr (see footnote 9200 and 9201) and the cost of dolomite-limestone absorbent at 4.38 dollars/ton (9200,274) to give a total operating cost of 1.26E05 dollars/1.0E12 Btu. No credit has been taken for sulfur recovery.

FTN. 9209-9211

9209 Entries in the table are based on energy input to each process of 1.00E12 Btu/yr. Entries for water pollutants are assumed to be the same as those from a controlled conventional coal-fired boiler since many of the unit process operations are the same. Thus from footnote 1908 organic emissions are 3.02-03 ton/10^{12} Btu. Dissolved solids amount to 18.2 ton/10^{12} Btu while increase in suspended solids is negligible. Capital cost for control is estimated at $ 1/Kw and operating cost is taken at 0.05 mills/Kw-hr (9221,233,234). The efficiency of the Pope, Evans and Robbins plant has been stated to be 37.2 percent with a plant heat rate of 9187 Btu/Kw-hr (9218). By taking the data from (9210,48) for a plant with an annual coal input of 106,000 tons and annual output of 271,000 Mw-hr, and using a heating value for the coal of 11,640 Btu/lb (9211,7), these values can be calculated approximately.

9211 Emission factors in the table were calculated assuming a Central region coal with a net caloric heating value of 12,500 Btu/lb, a sulfur content of 4.3 percent and an ash content of 8.5 percent. They apply to a 30 Mw single-level atmospheric pressure fluidized bed boiler power plant with a heat rate of 9187 Btu/Kw-hr and an overall plant efficiency of 36.8 percent (see footnote 9214). The plant operates at a temperature of 1500-1600 degrees F in the boiler and 12-14 FPS flue gas velocity with the integral carbon burn-up cell and regenerator bed sections operating at 1900-2050 degrees F (9212,30). One-eighth inch particle size limestone is added to the coal to give a calcium/sulfur ratio of 2/1 with limestone makeup added to account for a bed blowdown of about 10 percent. One percent sodium chloride is added with the limestone to enhance sulfur absorption (9212, 31 and 9211,5). Particulate emissions derive from the primary, carbon burn-up, and regenerator cells of the system. Each stream is cleaned with a high efficiency cyclone (eff.=85 percent), and the first two streams are further cleaned with an electrostatic precipitator (eff.=99+ percent). The tail gas of the regenerator effluent is recycled to the boiler (9212,5-6). From (9211,14), 12.1 percent of the ash in the coal appears in the flue gas before the electrostatic precipitator or 411.4 ton coal ash/1.00E12 Btu for an 8.5 percent ash coal. Also, from (9211,14) and (9213,8) which states that 10 percent of the flyash is calcium sulfate and 40 percent calcium oxide, one percent of the calcium in the boiler appears as calcium sulfate in the flyash and 9.6 percent of the calcium in the boiler appears as calcium oxide in the flyash. Accordingly, for the 4.3 percent sulfur coal requiring 22.165 lb limestone/1.0E6 Btu for a 2/1 Ca/S ratio, 0.086 lb of calcium appears in the flyash as 0.28 lb $CaSO_4$/1.0E6 Btu, and 0.826 lb

Ca appear in the flyash as 1.156 lb CaO/1.0E6 Btu. These amounts together with the ash amount to 1129.4 tons/1.0E12 Btu before the electrostatic precipitator which reduces particulates to 11.3 ton/1.0E12 Btu. Sulfur emissions derive from the boiler where about 80 percent of the sulfur in the coal is absorbed by the limestone. Ten percent of the sulfur in the coal appears in the solid waste, and 10 percent is emitted to the atmosphere (9213, 7). No sulfur emissions are expected from sulfur recovery from regenerator effluent since the stripped tail gas is recycled to the incoming boiler air. For a 4.3 percent sulfur coal, 12,500 Btu/lb heat content, the sulfur emitted to the atmosphere would be 189.2 ton/1.00E12 Btu or 378.4 ton SO_2/1.0E12 Btu. NO_x emissions derive from the boiler plant and amount to an average of 0.14 lb NO_x/1.00E6 Btu or 70 ton/1.00E12 Btu (9211,10). Hydrocarbons and CO are present in the flue gas in amounts on the order of 1000 PPM (volume basis) and 0.2-0.4 volume percent respectively, with 3 percent excess oxygen at the boiler outlet (9214). The coal producing these emissions on combustion in the Pope, Evans and Robbins fluidized bed boiler is a 4.6 percent sulfur, 12,340 Btu/lb, 15.8 percent ash coal. It is assumed that its combustion characteristics are similar to the 12500 Btu/lb, 4.3 percent sulfur coal used to compute other emissions. Therefore, CO and hydrocarbons were calculated using data given in (9211,14). Moles of flue gas/1.0E6 Btu were calculated as 13763.8 moles or 52.87 liters/mole. Hydrocarbons were calculated as methane to be .484 lb/1.0E6 Btu, 242 ton/1.00E12 Btu. Using a density of .0738 lb/CF (9215,1936) for CO at 0 degrees C and 760 mm pressure, CO was found to be 0.005 lb/1.0E6 Btu or 2.5 ton/1.00E12 Btu.

Air emissions summary for a 30 MW atmospheric pressure single-level fluidized bed boiler plant in tons/1.00E12 Btu

Particulates	11.3
Sulfur Oxides (as SO_2)	378.0
Nitrogen Oxides	70.0
Hydrocarbons (as CH_4)	242.
Carbon Monoxide	2.5
Total	703.8

9212 The amount of ash issuing from the combustion of 1.0E12 Btu, 8.5 percent coal would be 3400 ton. Makeup limestone is added at the rate of 3 times the weight of sulfur in the coal (9213,4). For a 4.3 percent coal, this would amount to 5160 ton limestone or 2002 ton Ca/1.0E12 Btu discarded from the system (limestone assumed to contain 97 percent calcium carbonate by weight). From (9213,8) four-fifths of the calcium in the waste is present as calcium oxide and one-fifth as calcium sulfate. This amounts to 1361.36 tons calcium sulfate and 2242.24 tons calcium oxide. Thus, subtracting particulate emissions of 11.3 ton/1.0E12 Btu, solid waste amounts to 6992.3 ton/1.0E12 Btu. Sulfur recovered not included.

9213 Fixed land impact for the atmospheric pressure fluidized bed boiler was taken as that given in footnote 9205 for the pressurized plant--1.62 acre-yr/1.00E12 Btu. From footnote 9212, solid waste is 6992.3 ton/1.00E12 Btu, with a flyash component of 3393.9 tons and a $CaSO_4$-CaO component of 3598.4 tons (appropriate proportions of the particulate emissions subtracted). From (9216,4), the average bulk density of coal flyash is 1 gm/cc or 62.4 lb/CF. From (9213,13) the calcium in the solid waste is present mostly as calcium oxide which has a bulk density of 53-64 lb/CF (9217,6-8). Thus an average density for the solid waste of 60.45 lb/CF was used. Assuming waste banks 30 ft high, the annual incremental land use due to solid waste was determined to be 0.177 acre-yr/1.0E12 Btu. Time-averaged over a 30 yr plant lifetime, total land impact is thus 4.28 acre-yr/1.0E12 Btu.

9214 Primary efficiency is given as 37.2 percent. (See footnote 9219). From (9221,234,446) electrical energy requirements for a 500 MWe plant amount to 5.022 MWe or one percent for thermal and chemical water pollution control. Hence the overall plant efficiency is reduced to 36.8 percent.

9215 (9212,32) states that a plant cost of 37 million dollars or 125 dollars/Kw is anticipated for a 300 MW atmospheric fluidized bed boiler plant (1972 figures). Referring to (9210,58) this estimate is seen to include land, structures, boiler plant equipment, turbine, electrical equipment and miscellaneous. Adding a 6 percent contingency fund (7.44 dollars/Kw) and water pollution control costs (See footnotes 9200,9201) the cost becomes 143.44 dollars/Kw. For a plant with a heat rate of 9280 Btu/Kw-hr, the fixed cost for an annual input of 1.0E12 Btu/yr, at a 10 PC fixed charge rate, is 2.35E05 dollars/1.0E12 Btu input. Coal costs at 49 cents/1.0E6 Btu are not included in operating costs (9200,273). Limestone costs of 4.35 dollars/ton delivered (9200,274) are updated to 1972 costs from (9208,162) for an input of 5160 ton/1.0E12 Btu input. Water pollution control costs are 0.10 mills/Kw-hr (see footnotes 9200,9201).

Operating and maintenance costs for an atmospheric plant were taken from (9207,132) on the assumption that these costs would be similar whether the plant has single-level beds or stacked beds. Updated to 1972 costs from (9208,162) this amounts to 0.94 mills/Kw-hr. Total operating cost, not including credit for sulfur recovered or flyash sold, is 1.34E05 dollars/1.0E12 Btu. Plant load factor is 75 percent.

9216 Emission factors in the table are based on an input of 1.0E12 Btu of Northwest region coal with a 0.5 percent sulfur, 6 percent ash and a heating value of 8800 Btu/lb. The calculations are made on the same bases as set out in footnote 9202, i.e. 92.9 percent of the input coal goes to the boiler and 7.1 percent goes to the coal combustor of the regenerator system. Thus, there are 113.6 lb coal/1.0E06 Btu producing 6.82 lb ash. The portion that is combusted in the boiler contains 0.53 lb sulfur requiring the addition of 10.46 lb dolomite for a 6/1 Ca/S ratio. The absorbent in this case is not actually necessary in order for sulfur emissions to meet EPA standards (1.2 lb SO_2/1.0E06 Btu), but is assumed added in the above proportions in order to have standardized data for a high, low, and medium sulfur coal. Using the mass balance diagram in (9204,100), it was determined that 0.30 percent of the ash in the coal and 0.0050 percent of the dolomite added to the coal appear as particulate emissions. There is an additional 90 percent efficient cyclone for flue gas clean up (see footnote 9202). Using these ratios, particulate emissions for this coal were determined as 0.0194 lb/1.0E06 Btu or 9.7 ton/1.0E12 Btu. NO_x emissions were assumed to be at the same low levels stated in footnote 9202, 67.3 ton/1.0E12 Btu, since they are primarily dependent on boiler temperature and restriction of excess air to the bed. SO_x was determined by calculating from (9200,272) that 86.4 percent of the sulfur in the coal is removed. Thus, for this coal, 71.8 tons SO_x are emitted/1.0E12 Btu. Summary of air emissions for a 635 Mw pressurized fluidized bed boiler power plant in tons/1.0E12 Btu

Particulates	9.7
Sulfur Oxides (as SO_2)	71.8
Nitrogen Oxides	67.3
Total	148.8

9217 Footnote 9216 states that the coal contains 6 percent ash which amounts to 3409 tons/1.0E12 Btu. Using the same basis as in footnote 9204 and (9204,H-100), the dolomite discarded to solid waste is 554.38 ton/1.0E12 Btu. Therefore, total solid waste is 3953.68 tons/1.0E12 Btu (particulate emissions subtracted).

9218 From footnote 9205, fixed land impact for a 1.0E12 Btu/yr plant is 1.62 acres. Weighting the solid waste load from footnote 9217 according to the densities given in footnote 9213 gives an overall density of 61.85 lb/CF. Assuming waste banks 30 ft high, the annual incremental land use due to solid waste is 0.0978 acres. Time-averaged over a 30 yr plant lifetime, total land impact is 1.47 acres-yr/1.0E12 Btu.

9219 From footnote 9207, operating costs include 0.98 mills/Kw-hr, water pollution control costs at 0.10 mills/Kw-hr, and the cost of dolomite-limestone absorbent at 4.38 dollars/ton or 2430.79 dollars/1.0E12 Btu. Total operating costs are thus 1.15E05 dollars/1.0E12 Btu. No credit taken for sulfur recovery.

9221 Air emissions given in the table are for a Northern Appalachian coal containing 2 percent sulfur, 10 percent ash and having a heating value of 12000 Btu/lb. Emissions are calculated on the same basis as those in footnote 9202, i.e., 92.88 percent of the input coal goes to the boiler and 7.12 percent goes to the coal combustor portion of the regenerator system. Thus, there are 83.33 lb coal/1.0E06 Btu, producing 8.33 lb ash. The portion combusted in the boiler contains 1.55 lb sulfur requiring 30.67 lb dolomite for a calcium/sulfur ratio of 6/1. A lower Ca/S ratio may suffice for adequate sulfur removal from the emissions of this coal. Using the same bases as in footnote 9216, particulate emissions were determined as 12.32 tons/1.0E12 Btu. NO_x emissions were assumed at 67.3 tons/1.0E12 Btu (see footnote 9216). SO_x was determined as 210.8 tons/1.0E12 Btu.

Summary of air emissions for a 635 Mw pressurized fluidized bed power plant in tons/1.0E12 Btu

Particulates	12.3
Nitrogen Oxides	67.3
Sulfur Oxides (as SO_2)	210.8
Total	290.4

9222 From footnote 9221, 1.0E12 Btu of coal produce 4165 ton ash. From footnotes 9204 and 9221, dolomite discarded from the system amounts to 1625.5 tons/1.0E12 Btu. Thus, total solid waste is 5778.2 ton/1.0E12 Btu (particulates subtracted).

9223 From footnote 9205, fixed land impact for a 1.0E12 Btu/yr plant is 1.62 acres. Weighting the solid waste loading from footnote 9222 according to densities given in footnote 9213 gives an average density for the solid waste of 61.3 lb/CF. Assuming waste banks 30 ft high, the annual incremental land use due to solid waste is 0.144 acres. Time-averaged over a 30 yr plant lifetime, total land impact is 3.78 acre-yr/1.0E12 Btu.

9224 From footnote 9207, operating costs include 0.98 mills/Kw-hr, water pollution control costs at 0.10 mills/Kw-hr, and the cost of dolomite-limestone absorbent at 4.38 dollars/ton or 7119.4 dollars/1.0E12 Btu. Total operating costs are thus 1.19E05 dollars/1.0E12 Btu. No credit taken for sulfur recovery.

9226 The emissions are calculated assuming a Northern Appalachian coal containing 2 percent sulfur, 10 percent ash and having a heating value of 12000 Btu/lb. Emission factors in the table are based on the operation of a 30 MW single-level atmospheric pressure fluidized bed power plant with a heat rate of 9187 Btu/Kw-hr and an overall plant efficiency of 36.8 percent. (See footnote 9209). Plant operation and methods of calculation are as given in footnote 9211. This coal produces 8.33 lb ash/1.0E6 Btu. There are 1.67 lb sulfur/1.0E6 Btu coal requiring 10.74 lb limestone (97 percent calcium carbonate) for a 2/1 calcium/sulfur ratio in the boiler. Thus, from footnote 9211, 0.135 lb calcium sulfate and 0.56 lb calcium oxide/1.0E6 Btu appear in the flyash to the electrostatic precipitator. In addition 12.1 percent of the ash in the coal also appears in the flyash, or 1.01 lb/1.0E6 Btu. Applying the final particulate control gives particulate emissions of 8.515 tons/1.0E12 Btu. From (9213,7) 10 percent of the sulfur in the coal is emitted to the atmosphere. Thus, for this coal, this amounts to 0.334 lb SO_x/1.0E6 Btu, calculated as SO_2, emitted. This is well below the EPA standard of 1.2 lb SO_2/1.0E6 Btu. NO_x emissions are a function of excess air in the boiler and bed temperature. So long as these are kept within the limits described in footnote 9211, NO_x was assumed constant for all the coals described. Thus, NO_x emissions amount to 70 ton/1.0E12 Btu. Hydrocarbon and carbon monoxide emissions are also assumed to remain constant from coal to coal as long as combustion conditions remain the same. Thus, hydrocarbon emissions are 242 ton/

1.0E12 Btu and CO is 2.5 ton/1.0E12 Btu. (See footnote 9211).
Summary of air emissons for a 30 Mw atmospheric pressure single-level fluidized bed boiler power plant in tons/ 1.0E12 Btu

Particulates	8.6
Sulfur Oxides (as SO_2)	167.0
Nitrogen Oxides	70.0
Hydrocarbons (as CH_4)	242.0
Carbon Monoxide	2.5
Total	490.1

9227 The amount of ash produced by the combustion of 1.0E12 Btu, 10 percent ash coal with a heating value of 12000 Btu/lb is 4166 tons. Makeup limestone is added at the rate of 3 times the weight of sulfur in the coal (9213, 4). Thus, 2505 tons limestone containing 971.94 tons calcium are discarded from the system. From (9213,8), 80 percent of the calcium in the waste is present as calcium oxide or 1088.6 tons. 20 percent of the calcium in the waste is present as calcium sulfate or 631.8 ton/ 1.0E12 Btu. Thus, subtracting particulate emissions, total solid waste is 5877.8 ton solid waste/1.0E12 Btu.

9228 From footnote 9213, fixed land impact for a 1.0E12 Btu/ yr plant is 1.62 acre. The ash component of the solid waste is 4161.7 tons and the CaO-$CaSO_4$ component is 1716.1 tons (appropriate proportions of particulate emissions subtracted). From footnote 9213, the bulk density of the fly ash is 62.4 lb/CF and the average density of the calcium fraction is 58.5 lb/CF. Assuming waste banks 30 ft high, the annual incremental land use due to solid waste is 0.147 acres. Time-averaged over a 30 yr plant lifetime, the total land impact is 3.82 acre-yr/1.0E12 Btu.

9229 Included in operating costs are limestone costs at 4.35 dollars/ton or 10896.75 dollars/10^{12} Btu (9200, 274 and 9208,162), water pollution control costs at 0.10 mills/Kw-hr (see footnotes 9200,9201) and operating and maintenance costs of 0.94 mills/Kw-hr (footnote 9215). Thus, total operating cost is 1.23E05 dollars/ 1.0E12 Btu.

9230 Emission factors in the table are for a Northwest region coal containing 0.5 percent sulfur, 6 percent ash and having a heating value of 8800 Btu/lb. They are derived on the same bases as are stated in footnotes 9209 and 9211.

Thus, for this coal there are 0.568 lb sulfur/1.0E6 Btu. The sulfur content of this coal is low enough to meet EPA emission standards of 1.2 lb SO_2/1.0E6 Btu without the use of any absorbent. However, it will be assumed that limestone in a 2/1 calcium/sulfur ratio is added to standardize the results on all coals used. Thus, this amount of sulfur would require 3.66 lb limestone as absorbent containing 1.42 lb calcium. 6.82 lb ash/1.0E6 Btu are also produced. From footnote 9211, 0.825 lb ash, 0.046 lb calcium sulfate and 0.191 lb calcium oxide appear in the flue gas/1.0E6 Btu before the 99 percent efficient electrostatic precipitator. Applying final particulate control, particulate emissions are found to be 5.31 tons/1.0E12 Btu. Sulfur oxides (calculated as SO_2) are 56.8 tons/1.0E12 Btu. Nitrogen oxides are 70 ton/1.0E12 Btu. Hydrocarbons (as CH_4) are 242.0 ton/1.0E12 Btu and CO is 2.5 ton/1.0E12 Btu. See footnote 9211.

Summary of air emissions for a 30 Mw atmospheric pressure single-level fluidized bed power plant in tons/1.0E12 Btu

Particulates	5.3
Nitrogen Oxides	70.0
Sulfur Oxides (as SO_2)	56.8
Hydrocarbons (as CH_4)	242.0
Carbon Monoxide	2.5
Total	376.6

9231 The amount of ash produced by 1.0E12 Btu of a 6 percent ash coal with a heating value of 8800 Btu/lb is 3409 tons. Makeup limestone is added at a rate of three times the weight of sulfur in the coal. Thus 852 tons limestone containing 330.576 tons calcium is discarded from the system. From (9213,8), 80 percent of the calcium is present in the waste as CaO or 370.25 tons CaO. Twenty percent of the calcium is present as $CaSO_4$ or 214.87 tons $CaSO_4$. Thus, subtracting particulate emissions, total solid waste load is 3988.8 tons/1.0E12 Btu.

9232 From footnote 9213, fixed land impact for a 1.0E12 Btu/yr atmospheric plant is 1.62 acres. From footnote 9231, the ash component of the solid waste is 3406.35 tons and the CaO-$CaSO_4$ component is 582.47 tons (appropriate proportions of particulates subtracted). From footnote 9213, the bulk density of the flyash is 62.4 lb/CF and that of calcium oxide-calcium sulfate is an average of 58.5 lb/CF. Assuming waste banks 30 ft high, the annual incremental land use due to solid waste is 0.0988 acres. Time-averaged over a 30 yr plant lifetime, the total land impact is 3.10 acre-yr/1.0E12 Btu.

9233 Included in operating costs are the cost of limestone to the boiler at 4.35 dollars/ton (9200,274), or 3706.20 dollars/1.0E12 Btu, water pollution control costs at 0.10 mills/Kw-hr (footnotes 9200,9201), and operating and maintenance costs of 0.94 mills/Kw-hr (footnote 9213). Thus, total operating costs are 1.16E05 dollars/1.0E12 Btu.

9234 All the national average impacts are arithmetic averages of the data given for the Central, Northern Appalachia, and Northwest regions.

VII. SOLVENT REFINED COAL

A. Introduction

The environmental impacts, cost, and efficiency for the activities and processes associated with solvent refined coal are shown in Table 5 of this report. Data have been developed for two regional coals: high sulfur Central and medium sulfur Northern Appalachia. The characteristics of the regional coal utilized are contained in the footnotes. Data are for an environmentally "controlled" condition. All of the cost data shown in Table 5 is based on a 90 percent plant load factor, or 328 operating days/yr. The values presented in this table are based on data accumulated during the Spring of 1974.

Each data entry is based upon an energy input of coal equivalent to 10^{12} Btu/yr. The Solvent Refined Coal process should be considered an integral part of the fossil fuel supply trajectory. Compared to the coal processing entries in the Phase I report, (HIT-593, Volume I), the environmental impacts have changed considerably in the distribution and power generation activities since the heating values, sulfur, and ash content of the SRC product are different. On the other hand, the coal extraction activities in the Phase I report may be used to complement or complete the total fossil fuel supply chain.

The Solvent Refined Coal process developed by the Pittsburgh and Midway Coal Mining Company is the basis for the energy - environmental data developed in this report. Although generally referred to as the coal de-ashing process, both ash and sulfur are removed. Figure 23 illustrates the process.

The process itself consists of six distinct operations described below:

1. Coal Preparation and Slurry. In this area the run-of-mine coal is crushed to less than 1/8-inch by 0 and then dried with thermal flash dryers to approximately 3% moisture. The coal particles are then mixed with a hot aromatic slurry and directed to the dissolvers.

2. Dissolving. The coal-slurry mixture is next hydrogenated under elevated temperature and pressure. The coal-slurry mixture has a contact time of approximately 15 minutes, although during actual operation this may vary somewhat.

3. Filtration The dissolved coal-solvent solution is next passed through a rotary precoat type filter where undissolved coal and ash are separated from the solution. This material is then sent to the Mineral Residue processing area in the form of a "filter cake" whereas the coal solution is further processed.

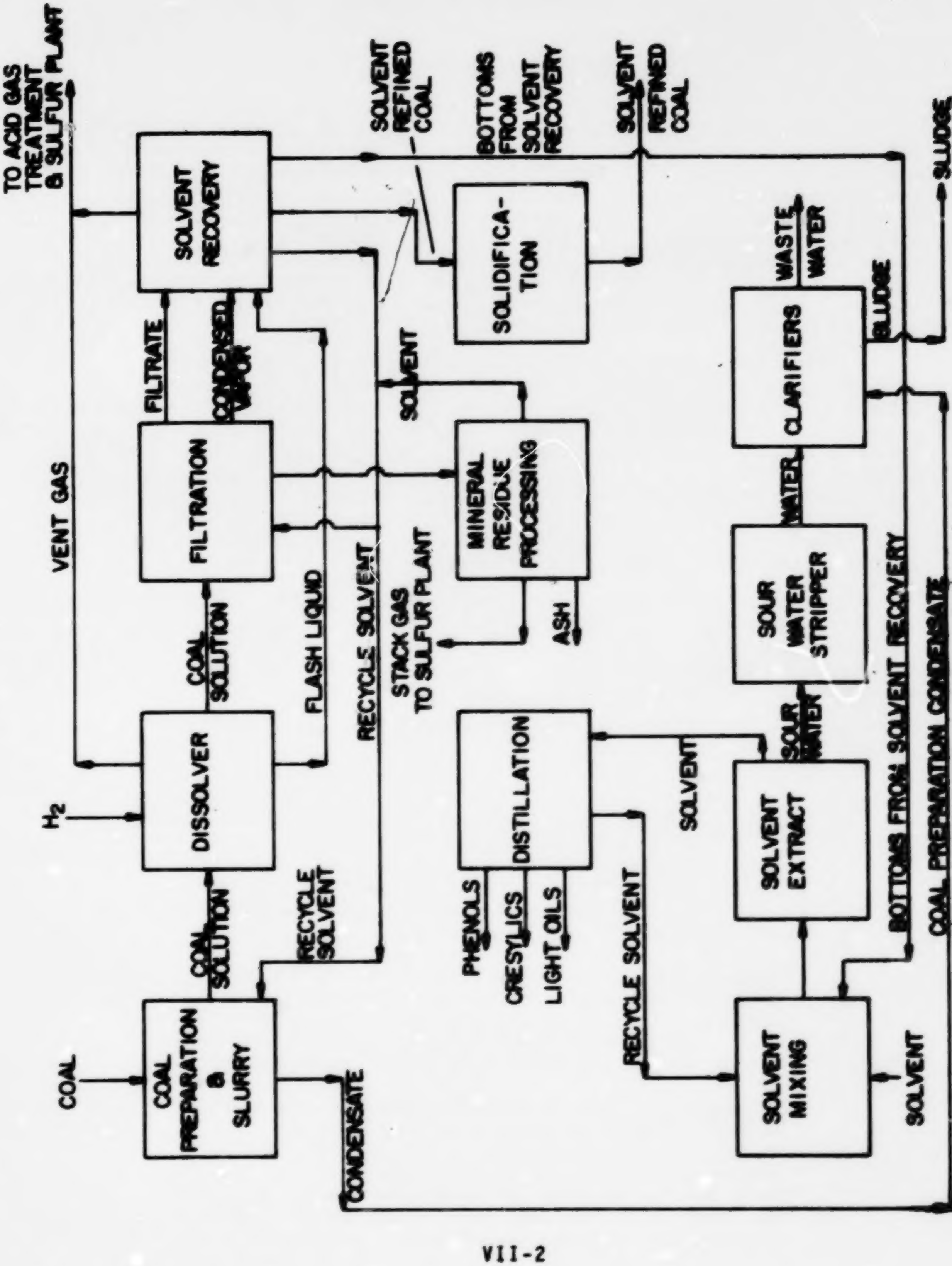
COAL
COAL PREPARATION & SLURRY
CONDENSATE
COAL SOLUTION
H2
DISSOLVER
RECYCLE SOLVENT
VENT GAS
COAL SOLUTION
FLASH LIQUID
RECYCLE SOLVENT
FILTRATION
FILTRATE
CONDENSED VAPOR
STACK GAS TO SULFUR PLANT
ASH
MINERAL RESIDUE PROCESSING
SOLVENT
SOLVENT RECOVERY
TO ACID GAS TREATMENT & SULFUR PLANT
SOLVENT REFINED COAL
SOLIDIFICATION
BOTTOMS FROM SOLVENT RECOVERY
SOLVENT REFINED COAL
PHENOLS
CRESYLICS
LIGHT OILS
DISTILLATION
RECYCLE SOLVENT
SOLVENT
SOLVENT MIXING
SOLVENT
SOLVENT EXTRACT
SOUR WATER
SOUR WATER STRIPPER
WATER
CLARIFIERS
WASTE WATER
SLUDGE
SLUDGE
BOTTOMS FROM SOLVENT RECOVERY
COAL PREPARATION CONDENSATE

Figure 23. Solvent Refined Coal Process (Ref. 9300)

4. Mineral Residue Processing. The filter cake containing most of the coal ash and minor portions of undissolved carbon is dried and burned. The filter cake has a heating value of approximately 4220 Btu/lb and provides a significant portion of the energy needed for operation of the plant.

5. Solvent Recovery. The coal-solvent solution is then flashed and further distilled to remove the solvent from the "liquid coal." The solvent is recycled to the slurry step.

6. Solidification. The coal product is solidified by use of flaking drums and stored as a solid de-ashed coal ready for shipment.

B. Impact Data Table and Footnotes

SOLVENT REFINED COAL

FUEL	REGION
COAL	AS INDICATED

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX. COL. 12)												AIR		
					DISSOLVED SOLIDS												
ROW	MNE-MON.	ACTIVITY PROCESS	ACIDS	BASES	PO_4	NO_3	OTHER	TOTAL (DS)	SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	
1		N. APPALACHIAN															
2	TRNSP	TRANSPORTATION															
3		TRUCK	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	3.34-02 4 9300	9.51-01 4 9300	6.98-02
4	CONVN	CONVERSION															
5	APSRC	SRC	0999	0999	3.65-01 4 9304	0999	5.90+02 4 9304	5.90+02 4	1.59+00 5 9304	2.98-02 5 9304	5.92+02 5	1.00-02 5 9304	1.00-02 5 9304	0.00+00 2 0997	1.89+01 3 9305	2.11-01 3 9305	2.42+01
6																	
7	DISTB	DISTRIBUTION															
8	UNITR	UNIT TRAIN	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	1.36+01 3 9311	1.20+00 3 9311	2.76+00
9	RBARG	RIVER BARGE	0998	0998	0998	0998	0998	0998	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.46+01 3 9319	1.42+00 3 9319	1.52+00
10	PPCVR	ELECTRIC POWER															
11	POGEN	POWER GENERATION	0.00+00 3 1908	0.00+00 3 1908	0999	0999	1.82+01 4 1908	1.82+01 4	0.00+00 3 1908	3.[illegible]-03 3 1908	1.82+01 4	0999	0999	0.00+00 3 9325	2.53+01 3 9323	2.84+02 3 9323	5.71+02
12																	
13		CENTRAL															
14	TRNSP	TRANSPORTATION															
15	TRUKK	TRUCK	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	1.75-02 3 9331	4.98-01 3 9331	3.63-02
16	CONVN	CONVERSION															
17	CCSRC	SRC	0999	0999	3.21-01 4 9335	0999	5.22+02 4 9335	5.22+02 4	1.40+00 5 9335	2.77-01 5 9335	5.24+02 5	6.78-03 5 9335	8.62-03 5 9335	0.00+00 2 0997	1.72+01 3 9336	1.87+01 3 9336	6.75+01
18																	
19	DISTB	DISTRIBUTION															
20	UNITR	UNIT TRAIN	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	0998	1.36+01 3 9342	2.88+00 3 9342	2.49+00
21	RBARG	RIVER BARGE	0998	0998	0998	0998	0998	0998	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3	0.00+00 3 0997	0.00+00 3 0997	0.00+00 3 0997	1.34+01 3 9349	5.31-01 3 9349	5.69-01
22	PPCVR	ELECTRIC POWER															
23	POGEN	POWER GENERATION	0.00+00 3 1908	0.00+00 3 1908	0999	0999	1.82+01 4 1908	1.82+01 4	0.00+00 3 1908	3.02-03 3 1908	1.82+01 4	0999	0999	0.00+00 3 9325	2.53+01 3 9323	2.84+02 3 9326	5.71+02
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	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
AL BTU	PARTICULATES	NO_x	SO_x	HYDRO-CARBONS	CO	ALDEHYDES ETC.	TOTAL	SOLIDS TONS / 10^{12}BTU	LAND $\left(\frac{\text{ACRE-YR}}{10^{12}\text{ BTU}}\right)$	DEATHS / 10^{12} BTU	INJURIES / 10^{12} BTU	MAN-DAYS LOST/10^{12}BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY (BTU/10^{12}BTU)	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
																			2
0999	3.34-02 4 9300	9.51-01 4 9300	6.90-02 4 9300	9.51-02 4 9300	5.78-01 4 9300	7.71-03 4 9300	1.70+00 4	0992	7.63-01 3 9301	0999	0999	0999	0999	1.00+00 2 9302	7.16+08 3 9301	4.04+03 3 9303	1.91+04 3 9303	2.31+04 3	3
																			4
0997	1.89+01 3 9305	2.11+01 3 9305	2.42+01 3 9305	4.84+00 3 9305	4.84-02 3 9305	3.62-01 3 9305	6.95+01 3	3.20+03 2 9306	2.54+00 3 9307	0999	0999	0999	0999	7.68-01 2 9308	7.66+10 2 9309	1.05+05 2 9310	1.19+05 2 9310	2.24+05 2	5
																			6
																			7
0999	1.36+01 3 9311	1.20+00 3 9311	2.76+00 3 9311	2.12+00 3 9311	2.87+00 3 9311	1.70-01 3 9311	2.48+01 3	0.00+00 2 9315	3.43+01 4 9314	6.10-02 2 9316	5.85-01 2 9316	5.95+01 2 9316	0999	1.00+00 2 9313	1.17+10 3 9312	4.22+03 3 9317	6.62+04 3 9317	7.04+04 3	8
0997	1.96+01 3 9319	1.42+00 3 9319	1.52+00 3 9319	9.10-01 3 9319	1.22+00 3 9319	7.06-02 3 9319	2.49+01 3	0998	0998	0999	0999	0999		1.00+00 2 9321	1.59+10 3 9320	3.91+03 3 9322	2.86+04 3 9322	3.25+04 3	9
																			10
9325	2.53+01 3 9323	2.84+02 3 9323	5.71+02 3 9323	4.74+00 3 9323	1.50+01 3 9323	7.86-02 3 9323	9.01+02 3	6.30+00 2 9326	6.27+00 3 9330	1.11-03 3 9327	1.06-01 3 9327	6.41+00 3 9327		3.97-01 3 9328	0.00+00 3 0997	2.58+05 3 9329	4.14+05 3 9329	6.72+05 3	11
																			12
																			13
																			14
0999	1.75-02 3 9331	4.90-01 3 9331	3.63-02 3 9331	4.98-02 3 9331	3.03-01 3 9331	4.04-03 3 9331	9.09-01 3	0999	4.01-01 3 9332	0999	0999	0999	0999	1.00+00 2 9333	3.74+08 3 9332	3.79+03 3 9334	1.15+04 3 9334	1.53+04 3	15
																			16
0997	1.72+01 3 9336	1.47+01 3 9336	4.75+01 3 9336	4.30+00 3 9336	4.30-02 3 9336	3.21-01 3 9336	8.81+01 3	3.92+03 2 9337	2.24+00 3 9338	0999	0999	0999	0999	6.86-01 2 9339	6.81+10 2 9340	1.22+05 2 9341	9.00+04 2 9341	2.06+05 2	17
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0999	1.36+01 3 9342	2.88+00 3 9342	2.49+00 3 9342	1.02+00 3 9342	2.88+00 3 9342	1.50-01 3 9342	2.37+01 3	0998	3.10+01 3 9443	6.10-02 2 9316	5.85-01 2 9316	5.95+01 2 9316	0999	1.00+00 2 9445	1.06+10 3 9346	3.83E+03 3 9347	6.01E+04 3 9347	6.39E+04 3	20
0997	1.34+01 3 9349	5.31-01 3 9349	5.69-01 3 9349	3.41-01 3 9349	4.55-01 3 9349	2.65-02 3 9349	1.53+01 3	0998	0998	0999	0999	0999	0999	1.00+00 2 9445	4.30+09 3 9346	3.91+03 3 9350	2.86+04 3 9350	3.25+04 3	21
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9325	2.53+01 3 9323	2.84+02 3 9324	5.71+02 3 9323	4.74+00 3 9323	1.50+01 3 9323	7.86+02 3 9323	9.01+02 3	6.30+00 2 9326	6.27+00 3 9330	1.11-03 3 9327	1.06-01 3 9327	6.41+00 3 9327	0999	3.97-01 3 9328	0.00+00 3 0997	2.58+05 3 9329	4.14+05 3 9329	6.72+05 3	23
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TABLE 5. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL SOLVENT REFINED COAL SUPPLY

Footnotes for Table 5

1908 The basis for water pollutant calculations is the proposed effluent limitations guidelines and new source performance standards for the steam electric power generating point source category given in (1921). For new plants, best available demonstrated control technology (BADCT) requires effluent pH control in the range of 6-9. Hence acids and bases discharge will be negligible. BADCT also specifies total suspended solids levels no greater than 15 mg/l for all intermediate and low volume waste effluents. At this level of control there will generally be no net increase in suspended solids in water passing through the power plant system. Organics (oil and grease) must be controlled to 10 mg/l to meet BADCT standards. Hence from (1921, 232) these emissions will amount to .0736 ton organics/10^6 ton coal or 3.02-03 ton/10^{12} Btu. Information on the increase in total dissolved solids of water used in power plants is not readily available and was synthesized from (1922,10,12,20,22). Based on this data the net increase in total dissolved solids for water used by the power plant is 18.2 ton/10^{12} Btu.

9300 Table entries for N. Appalachian coal transportation are based on the haulage of 1.00E+12 Btu/yr of coal (4.17E+04 T/yr). The average distance from mine tipple to prep plant is 7.3 miles and the average truck capacity is 22 tons (9314,344). The average fuel consumption of diesel trucks is 7.0 gal/1000 TMI (9303). To haul 1.00E+12 Btu/yr of coal, 1896 round trips are required. For a plant processing 1.00E+12 Btu/yr, 3200 T/yr of ash is produced (see SRC-Solid Waste). This requires 146 full load trips back to mine. Assuming a gross to tare of 2.5, 5.14 E+03 gallons are consumed. From (9303), the air pollutants are -

Particulates	3.34E-02T/1.00E+12 Btu
SO_x	6.94E-02T/1.00E+12 Btu
CO	5.78E-01T/1.00E+12 Btu
HC	9.51E-02T/1.00E+12 Btu
NO_x	9.51E-01T/1.00E+12 Btu
ALD	7.71E-03T/1.00E+12 Btu

Road dust is assumed to be controlled by water sprays.

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FTN. 9301-9304

9301 For a heating value of 5.83E+06 Btu/BBL and a fuel consumption of 5143 gal, ancillary energy for truck haulage is 7.14E+08 Btu. Land impact for truck haulage is based on a 60 ft rdwy, a mine to plant distance of 7.3 miles (9314,344), and a 1 acre settling pond per mile. For a plant processing 10,000 tpd, the fixed land impact is 60.1ac. For a plant processing 1.00E+12 Btu/yr, the fixed land impact is .763 ac-yr/ 1.00E+12 Btu.

9302 Coal loss during transportation is assumed to be controlled by water sprays. Primary efficiency is 1.00E+00.

9303 Capital cost for truck haulage consists of the following (9316,7/26):

Road Grader	1.35E+05
Dump Trucks(5)	9.68E+05
Water Truck	2.20E+04
Settling Ponds(7)	1.40E+04
Coal Trucks(20)	8.00E+05
Total	1.94E+06 dollars for 2MMT/yr mine

Operating costs are based on (9312,583,586). At 40,000 dollars/truck and a fuel consumption of 5143 gal, operating cost(including 720 dollars/1.0E+12 Btu for fuel, 13140 dollars/1.0E+12 Btu for labor, and 5256 dollars/1.0E+12 Btu for maintenance) is 1.91E+04 dollars/ 1.00E+12 Btu. At 10 percent fixed charge rate, capital cost is 4.04E+03 dollars/1.00E+12 Btu.

9304 Impacts for the solvent refined coal process are based on energy and material balances in (9300). A Northern Appalachian coal having the following proximate analysis was used:

Moisture	3.40 percent
Ash	7.70 percent
Sulfur	1.80 percent
FC+VMA	89.90 percent

Heating value 12,000 Btu/lb

In order to maintain continuity in product and by-product streams, the fixed carbon and volatile matter is fixed. For a Northern Appalachian coal, equivalent feed is 8.42E+05 lb/hr. From (9300) wastewater stream from the dissolvers is 95,471 lb/hr and the probable composition is (9313,9300):

Phenol	3000 lb/hr
NH_3	157 lb/hr
TDS	765 lb/hr
S/S	50 lb/hr
CN/SCN	27 lb/hr
Oil	3 lb/hr

H_2S is assumed at 158 lb/hr to keep overall plant sulfur balance at 96.7 percent figure. No condensate from coal drying will be formed since coal is approximately 3 percent moisture and most water will be driven off as vapor. Sanitary waste is based on 100 gallon/day per employee and consist of (9301):

Flow	4843 lb/hr
BOD	1.1 lb/hr
COD	1.4 lb/hr
S/S	1.3 lb/hr

Total plant blowdown (makeup water) is 1.45E+06 lb/hr (9300) and will have the following analysis (9317):

TDS	11,043 lb/hr
PO_4	7.3 lb/hr
S/S	25 lb/hr

Blowdown is held in a holding or cooling pond and is then released (9300). The wastewater treatment system consists of the following units (9301,9304, 9305,9311)-phenol solvent extraction, sour water stripping, primary clarification, activated sludge, and secondary clarification. Removal efficiencies are given in references. To process 1.00E+12 Btu/yr of 12000 Btu/lb N. Appalachian coal, the scale factor is 1.26E-02 times figures given in (9300) and using 8.42E+05 lb/hr fixed carbon and volitile matter feed. Water pollutants based on discharging of dissolver waste, sanitary waste, and cooling tower blowdown after treatment are (on a 1.00E+12 Btu/yr basis):

	Effluent	
	Ton/Yr	PPM
Oil	1.49E-02	1.94E-01
CN/SCN	1.35E-01	1.76E+00
NH_3	2.50E-02	3.25E-01
H_2S	1.15E-02	1.50E-01
Phenol	1.49E-02	1.94E-01
S/S	1.59E+00	2.07E+01
BOD	1.00E-02	1.30E-01
COD	1.00E-02	1.30E-01
TDS	5.90E+02	7.67E+03
PO_4	3.65E-01	4.75E+00
H_2O	7.70E+04	

9305 Air pollutants associated with the solvent refining process primarily consist of emissions from fuel gas combustion, Claus plant tail gas, and coal preparation plant.

Claus Plant

SO_2 emissions are based on the total available sulfur in the input coal. For processing 8.42E+05 lb/hr of N. Appalachian coal with 1.8 percent sulfur content, 11,951 lb/hr of sulfur is recovered of which 146 lb/hr is generated as H_2S in the sour water stripping operation, 4410 lb/hr is recovered from a Wellman-Lord scrubber as SO_2 resulting in filter cake burning, and the remaining 7407 lb/hr H_2S is recovered as H_2S in acid gas treating. Assuming a 95 percent removal efficiency of the Wellman-Lord scrubber, 232 lb/hr S is emitted (9318). The Claus plant recovers 99.9 percent of input sulfur. 0.1 percent is emitted to the atmosphere as SO_2 (9319, 127).

SO_2 emissions are:

Filter Cake Combustion Stack Gas	1829 T/yr-	464 lb/hr
Claus Plant Tail Gas	94 T/yr-	24 lb/hr

Fuel Gas Combustion

Combustion of the fuel gas produced (868 Btu/SCF) is based on the fuel requirements and distribution given in (9300). The following is a list of combustion sources:

Thermal Driers (from dissolvers)	1309E+06 Btu/hr
Mineral Residue Processing	50E+06 Btu/hr
Solvent Recovery	630E+06 Btu/hr
Hydrogen Plant	502E+06 Btu/hr
Sulfur Incinerator	52E+06 Btu/hr

Air emissions are based on combusting a total of 2.54E+09 Btu/hr (9303,2/72), and the heating value ratio of 868 Btu/SCF to that of natural gas 1050 Btu/SCF. Preparation of coal in flash dryers accounts for additional particulate emissions (9303, 8/10). Processing 8.39E+05 lb/hr of coal (at 3 percent moisture) particulate emissions are 1413 T/yr using 95 percent efficient cyclone. Total air pollutants are (tons/yr):

Area	Part.	SO_x	CO	HC	NO_x	ALD
Coal Prep.	1413.00	-	1.97	197	861	14.76
Mineral Proc.	3.40	1829	0.08	7.52	32.9	0.56
Solvent Ext.	42.6	-	0.95	94.80	414.8	7.11
H_2 Plant	33.94	-	0.76	75.60	330.8	5.67
Claus Plant	3.50	94	0.08	7.80	34.0	0.59
	1496.40	1923	3.84	382.72	1673.5	28.69

These data are based on processing 8.42E+05 lb/hr. To process 1.00E+12 Btu/yr of 12000 Btu/lb N. Appalachian coal, the scale factor is 0.0126.

9306 Solid waste from the solvent refining process results primarily from ash removal in the mineral residue processing area. As the filter cake is combusted, the ash is produced. For an SRC plant processing 8.42E+05 lb/hr of N. Appalachian coal with a 7.7 percent ash content, 64,867 lb/hr of ash will be produced (9300). To process 1.00E+12 Btu/yr, 3.20E+03 ton/yr of ash will be produced. The ash will not have a land impact since it is assumed to be returned to the mine for burial.

9307 A 10,000 T/D SRC plant is assumed to occupy 200 acres. For a plant processing 1.00E+12 Btu/yr (127 T/D) land impact is 2.51 Ac-yr.

9308 Primary efficiency is based on the input of 8.42E+05 lb/hr of 1.20E+04 Btu/lb N. Appalachian coal and an output of 4.88E+05 lb/hr of 1.59E+04 Btu/lb solvent refined coal. Primary thermal efficiency is 76.8 percent. The thermal efficiency would be higher if input of hydrogen and output of light oils is considered (9300).

9309 Ancillary energy for a 10,000 T/D solvent refined coal plant is approximately 7.71E+08 Btu/hr of natural gas (9300,5-11). Of the 3.14E+09 Btu/hr fuel gas required, 2.37E+09 Btu/hr is supplied by the production of high Btu refinery gas. The additional gas (natural gas) must be purchased. It is anticipated that a solvent refined coal plant will make use of a considerable amount of waste heat and will actually export 32 MW of electrical power.
For a plant processing 1.00E+12 Btu/yr, ancillary energy is 7.66E+10 Btu/yr.

9310 Capital cost for a 10,000 T/D solvent refined coal plant is based on data from (9300). The process is utilizing 8.33E+05 lb/hr and a Northern Appalachian coal will require 8.42E+05 lb/hr. Cost for coal prep, processing, filtration, and sulfur recovery have been linearly adjusted to reflect difference in coal input rates (lb/hr). Additionally, another 1.63E+06 dollars has been added to cover the cost of sour water strippers and activated sludge units. Costs have been adjusted to 1972 dollars using a 12 percent increase (from 1969). Total annualized cost is 8.34E+06 dollars at 10 percent fixed charge rate. For a plant processing 1.00E+12 Btu/yr, the total capital cost is 1.05E+05 dollars. Plant load factor is 90 percent.

Operating cost is based on 9.58E+06 dollars/yr and a by-product credit of 1.16E+06 dollars/yr. Total cost is scaled up 12 percent to reflect 1972 cost (9300).

9311 In a study conducted by the Bureau of Mines (9320) the average haulage distance from mines in this region is about 320 miles. Energy consumption by freight trains is assumed to apply to unit and mixed trains (9335). Trains are assumed to have a gross to tare ratio of 4 and consist of 3 locomotives. It is further assumed that SRC is transported in solid form and that it presents no unusual difficulties in handling. To haul 1.00E+12 Btu/yr, the total weight of a unit train is 41982 tons. To haul 320 miles, a total of 6.72E+04 gal of diesel fuel is consumed by the 3 locomotives. Return trip requires 1.68E+04 gal. Air pollutants for diesel consumption and loading and unloading are given as follows (9303,3-7,7-4):

	Lb/1000 Gal	Locomotive T/1.00E+12 Btu	Loading/Unloading T/1.00E+12 Btu
Particulates	25	1.04+00	12.60+00
SO_x	65	2.76+00	
CO	70	2.97+00	
HC	50	2.12+00	
NO_x	75	3.20+00	
ALD	4	1.70-01	

9312 Ancillary energy for haulage of 1.00E+12 Btu/yr is 1.17E+10 Btu. Figure is based on consumption of 8.40E+04 gallons of diesel fuel with a heating value of 5.83E+06 Btu/bbl (Footnote 9311).

9313 Primary efficiency is 1.00E+00 percent. It is assumed that miscellaneous losses due to spillage are negligible.

9314 Land impacts associated with the distribution of SRC are assumed to consist of a 320 mile rail line, footnote 9311, with a R/W of 60 ft. This line would serve a 10,000 T/D SRC plant producing 6.80E+13 Btu/yr. Land impact for shipping 1.00E+12 Btu/yr is 3.43E+01 A-yr.

9315 Solid waste for SRC haulage by rail assuming negligible losses is 0.00E+00 ton/yr.

9316 For the period from 1969 to 1970, shipment of coal accounted for 27 percent of the total tons of freight shipped by rail (9321,559). Of the total coal shipped, 1.00E+12 Btu/yr of SRC would account for 0.01 percent (total 330 MMT). During the same period an average of 2255 fatalities occurred and 21,666 persons were injured in rail accidents (9322). These figures include all accidents. Injuries to employees on duty average 16,250 persons and 93 man-days were lost per injury (9322). Hence, for every 1.00E+12 Btu/yr hauled, there are 0.061 fatal injuries, 0.585 non-fatal injuries, and 59.5 man-days lost.

9317 Freight charges for haulage by unit train are 0.0061 dollars/TMI (9322,10) in 1969 cost. ICC imposed an 8P and 6P freight rate increase in 1970 and 1971, respectively, to 0.0070 $/TMI. Haulage of 3.15E+04 ton of SRC, equivalent to 1.00E+12 Btu, a distance of 320 miles is 7.04E+04 dollars total cost. From (9323, 67/70) fixed cost (depreciation only) is about 6 percent of total annual cost. Hence, fixed cost is 4.22E+03 $ and annual operating cost is 6.62E+04 $.

9319 The average capacity of a barge is 25000 tons (9326, 35), and the average haul distance is assumed to be 800 miles (approximate distance from Erie,Pa. to Chicago via Great Lakes). Air emissions are based on (9303,3-11). To haul 1.00E+12 Btu of SRC 1.26 round trips must be made. Pollutants are:

	Lb/Mi	T/1.00E+12 Btu
Particulates	2	2.02E+00
SO_x	1.5	1.52E+00
CO	1.2	1.22E+00
HC	0.9	9.10E-01
NO_x	1.4	1.42E+00
ALD	0.07	7.06E-02

From (9303,7-4) an additional 12.6 tons of particulates are emitted when loading and unloading SRC.

9320 Ancillary energy is based on a fuel consumption of 378 Btu/TMI (9325), a capacity of 25000 tons (9326, 35), and distance of 800 miles. Assuming a gross to tare ratio of 4 and that barges return empty to their origin, energy required is 1.59E+10 Btu for the 1.26 round-trips.

9321 Neglecting miscellaneous transportation losses, primary efficiency is 100 percent.

9322 The cost for shipping coal (SRC) in 1971 by barge was 0.97 dollars/ton (9327,37) of which 12 percent (inclusive of insurance and depreciation) is fixed cost. This agrees with data in (9328,18). Cost to haul 3.15E+04 tons of SRC would be 2.86E+04 dollars operating and 3.91E+03 dollars fixed. Cost is escalated 6 percent to reflect 1972 cost.

9323 Air pollutants for power generation are based on an SRC input of 1.00E+12 Btu/yr or 31,446 tons/yr. SRC composition will have a sulfur content not greater than 0.95 percent and a heating value of approximately 15,900 Btu/lb. Ash content will be less than 0.1 percent. It is assumed that pulverized SRC will perform similar to typical coals and will present no unusual combustion difficulties. All pollutant figures are based on (9303) utilizing the appropriate ash and sulfur content. Pollutants are as follows:

	Lb/Ton SRC	Ton/1.00E+12 Btu
Particulates	16(Ash)	2.53E+01
SO_x	38(Sulfur)	5.71E+02
CO	1.0	1.58E+01
HC	0.3	4.74E+00
NO_x	18.0	2.84E+02
ALD	.005	7.86E-02
	Total	9.01E+02

9325 By use of mechanical draft wet cooling towers, thermal pollution may be virtually eliminated.

9326 From (9300) the ash content of solvent refined coal is 0.1 percent. For a SRC feed of 31,446 ton/yr (1.00E+12 Btu), 31.5 tons of ash are available as solid waste. In practice, however, 80 percent of this material is emitted as particulates during combustion. The remaining 20 percent results in ash or solid waste. Solid waste is 6.30 ton/1.00E+12 Btu.

9327 Occupational health statistics are based on reference (9330,46). 0.166 men per MWE is the basis for the calculation. Injury data is from (9331,35). Half the combined deaths and permanent injuries are assumed to be fatal injuries. Permanent total disabilities are considered to represent 6000 days lost while other disabilities are estimated as 100 days lost. Man-days lost are for injuries only.

9328 Power plant efficiency is based on 60.3 percent heat rejection rate. One-sixth of this is emitted through the stack gas. It is assumed the boiler and turbine efficiency is similar to conventional fossil fired plants (9333), however in actuality they will be somewhat higher due to the reduced ash content and higher heating value of the solvent refined coal. No actual tests have been performed. From (9300) turbine heat rate is 7750 Btu/Kw-hr resulting in a turbine efficiency of 44 percent, and steam generator efficiency of 90.1 percent (9300,5-6). Total plant efficiency is 39.7 percent.

9329 Capital and operating cost are based on (9300). Capital cost for a power plant with an input of 5.70E+13 Btu/yr is 1.31E+08 dollars. At a fixed charge rate of 10 percent, capital cost on a 1.0E+12 Btu input basis is 2.58E+05 dollars (1972). Operating cost is 4.14E+05 dollars including fuel, interest, taxes, insurance, and depreciation.

9330 A typical size for a 3000 MWE plant with flyash controls is 1200 acres, including 350 for ash storage and 40 for coal storage from (9332,11,14). For a solvent refined coal plant, ash storage will not be required, hence fixed land impact is 6.27 acres/1.00E+12 Btu input.

9331 Tables entries for Central coal transportation are based on the haulage of 1.00E+12 Btu/yr or 4.17E+04 ton/yr of coal. The average distance from mine tipple to prep plant is 3.8 miles (9314,344). The average truck haul capacity is 59 tons (9314,344). The average truck diesel fuel consumption is 7 gal/1000 TMI (9303). To haul 1.00E+12 Btu/yr, 707 round trips are required of which 67 return trips are full loads (haul solid waste, ash, back to the mine, see solid waste). Assuming a gross to tare of 2.5, a total of 2693 gallons of diesel fuel is consumed. From (9303,3-7) air pollutants are as follows:

	Lb/1000 Gal	T/1.00E+12 Btu
Particulates	13	1.75E-02
SO_x	27	3.63E-02
CO	225	3.03E-01
HC	37	4.98E-02
NO_x	370	4.98E-01
ALD	3	4.04E-03

9332 For a heating value of 5.83E+06 Btu/BBL and a total fuel consumption of 2693 gallons, ancillary energy for truck haulage is 3.74E+08 Btu. Land impact for truck haulage is based on a 60 ft R/W, a mine to plant distance of 3.8 miles (9314,344), and a 1 acre settling pond per mile (control of sediment). For a plant processing 10,000 tons/day, the fixed land impact is 31.6 acres. For a plant processing 1.00E+12 Btu/yr, the fixed land impact is 0.401 A-yr/1.00E+12 Btu.

9333 Coal loss during transportation is assumed to be negligible. Dust control is accomplished by water sprays. Primary efficiency is 100 percent.

9334 Capital and operating cost are based on (9316,7/26). For truck haulage capital cost are as follows:

Road Grader(2)	1.32E+05 dollars
Dump Trucks(5)	9.68E+05 dollars
Water Truck	2.20E+04 dollars
Settling Pond(4)	8.00E+03 dollars
Coal Trucks(10)	6.90E+05 dollars
	32E+06 dollars for 2MMT/yr mine

For a truck haulage of 1.00E+12 Btu/yr at 10 percent fixed charge rate, costs are 3.79E+03 dollars. Operating costs are based on (9312,586). At 69,000 dollars/truck and a fuel consumption of 2693 gallons, operating cost (4.54E+03 dollars for maintenance, 3.77E+02 dollars for fuel, and 6.56E+03 dollars for labor, on a 1.00E+12 Btu/yr basis) is 1.15E+04 dollars/1.0E+12 Btu.

9335 Impacts for the solvent refined coal process are based on energy and material balances in (9300). A Central coal having the following proximate analysis was used:

Moisture	11.20 percent
Ash	9.40 percent
Sulfur	3.50 percent
FC+VMA	79.40 percent

Heating value 12,000 Btu/lb

In order to maintain continuity in product and by-product streams, the fixed carbon and volitile matter is fixed. For a Central coal, the equivalent feed is 8.64E+05 lb/hr at 3.0 percent moisture as in reference (9300). From (9300) the wastewater stream from the dissolver is 96,599 lb/hr and the probable composition is (9313, 9300):

Phenol	3000 lb/hr
NH_3	160 lb/hr
TDS	825 lb/hr
S/S	51 lb/hr
CN/SCN	27 lb/hr
Oil	3 lb/hr

H_2S is assumed at 349 lb/hr to keep the overall plant sulfur balance at 96.5 percent. Condensate from the coal prep plant is approximately 11,379 lb/hr with about 10 percent oil and solvent content. This waste stream is generated during thermal drying. Sanitary waste is based on 100 gal/day/employee and consists of (9301):

Flow	4843 lb/hr
BOD	1.1 lb/hr
COD	1.4 lb/hr
S/S	1.3 lb/hr

Total boiler and cooling water makeup is 1.45E+06 lb/hr (9300). Blowdown will consist of the following pollutants (9317):

TDS	11,043 lb/hr
PO_4	7.3 lb/hr
S/S	25 lb/hr

This blowdown will be held in a holding or cooling pond and is periodically released (9300). The waste water treatment system consists of the following units (9301,9304,9305,9311): phenol solvent extraction, sour water stripping, primary clarification, activated sludge, and secondary clarification. Removal efficiencies are given in references. To process 1.00E+12 Btu/yr of 12,000 Btu/lb Central coal, the scale factor is 1.12E-02 times figures given in (9300) and using 8.64E+05 lb/hr feed (FC+VMA fixed). Water pollutants are based on discharging of dissolver waste, coal prep waste, sanitary waste, and blowdown waste after treatment.

	Effluent	
	Ton/Yr	PPM
Phenol	1.33E-02	1.95E-01
H_2S	1.10E-02	1.62E-01
S/S	1.40E+00	2.06E+01
NH	2.20E-02	3.23E-01
CN/SCN	1.19E-01	1.75E+00
TDS	5.22E+02	7.67E+03
Oil	2.64E-01	3.88E+00
BOD	6.78E-03	9.97E-02
COD	8.62E-03	1.27E-01
PO_4	3.21E-01	4.72E+00
H_2O	6.82E+04	

9336 Air emissions associated with the solvent refining process primarily consist of emissions from fuel gas combustion, Claus plant tail gas, and coal preparation plant.

Claus Plant

SO_2 emissions are based on the total available sulfur in the input coal. For processing 9.43E+05 lb/hr of 3.5 percent sulfur coal, 26,410 lb/hr of sulfur is recovered in the Claus plant. 324 lb/hr of this sulfur is recovered in sour water stripping and 9734 lb/hr is recovered via a Wellman-Lord scrubber system on filter cake burning process. The remaining sulfur is recovered in acid gas recovery of fuel gases. Assuming a 95 percent removal efficiency of the Wellman-Lord system (9318), 1025 lb/hr of SO_x is emitted. The Claus plant recovers 99.9 percent of the input sulfur. 0.1 percent is emitted as SO_2 (9319,127). SO_2 emission is as follows:

Filter Cake Combustion Stack Gas	4041 T/Yr-	1025 lb/hr
Claus Plant Tail Gas	205 T/Yr-	53 lb/hr

Fuel Gas Combustion

Combustion of the fuel gas produced (868 Btu/SCF) is based on the fuel requirements and distribution given in (9300). The following is a list of combustion sources:

Thermal Driers (from dissolvers)	1309E+06 Btu/hr
Mineral Residue Processing	50E+06 Btu/hr
Solvent Recovery	630E+06 Btu/hr
Hydrogen Plant	502E+06 Btu/hr
Sulfur Plant Incinerator	52E+06 Btu/hr

Air emissions are based on combustion of the total 2.54E+09 Btu/hr (9303,2/72), and the heating value ratio of 868 Btu/SCF to that of natural gas, 1050 Btu/SCF. Preparation of coal in flash driers accounts for additional particulate emissions (9303, 8/10). Processing 8.64E+05 lb/hr of coal (3.0 percent moisture) particulate emissions are 1362 T/yr using a 95 percent efficient cyclone system. Total pollutants are (tons/yr):

	Part.	SO_x	CO	HC	NO_x	ALD
Coal Prep.	1451.00	-	1.97	197.00	861.00	14.76
Mineral Proc.	3.38	4041	0.08	7.52	32.90	0.56
Solvent Ext.	42.59	-	0.95	94.80	414.75	7.11
H_2 Plant	33.94	-	0.76	75.60	303.75	5.67
Claus Plant	3.50	204	0.08	7.80	34.00	0.59
	1534.41	4245	3.84	382.72	1673.40	28.69

These figures are based on processing 8.64E+05 lb/hr. To process 1.00E+12 Btu/yr of 12000 Btu/lb Central coal, the scale factor is 0.0112.

9337 Solid waste from the solvent refining process is a result of combustion of the filter cake being used as supplementary fuel. This ash is generated in the mineral processing step. For processing 9.43E+05 ton/hr of Central coal having an ash content of 9.4 percent, 88,663 lb/hr of ash is generated in the fluidized bed boiler. For a SRC plant processing 1.00E+12 Btu/lb of Central coal (HV=12000 Btu/lb), ash or solid waste is 3.92E+03 ton/yr. This solid waste will have no land impact since it will be transported back to the mine for ultimate disposal (9300).

9338 Land impacts have been interpolated from (9334,7). It is assumed that a solvent refining operation will occupy 200 acres since product distillation, upgrading, and pipeline gas production will not be required. On a 1.00E+12 Btu/yr basis, land impact is 2.24 A-yr.

9339 Primary efficiency is based on the input of 9.43E+05 lb/hr of 12000 Btu/lb Central coal. Since fixed carbon and volatile matter is fixed with that of the coal in (9300), the product streams are consistant with that in (9300). Primary thermal efficiency accounts for only primary coal input and SRC output. For a SRC heating value of 15,900 Btu/lb, product is 4.88E+05 lb/hr, and primary efficiency is 68.6 percent. If by-product streams are considered, efficiency would be somewhat higher.

9340 Ancillary energy for a 10,000 T/D solvent refined coal plant is approximately 7.71E+08 lb/hr of natural gas (9300,5-11). Of the 3.14E+09 Btu/yr fuel gas required, 2.37E+09 Btu/hr is supplied by the production of high Btu refinery fuel gas. The additional gas (natural gas) must be imported. It is anticipated that a solvent refined coal plant will make use of a considerable amount of waste heat, and will be able to utilize this heat to produce electricity. Approximately 32 MW may be exported. Ancillary energy for a plant processing 1.00E+12 Btu/yr is 6.81E+10 Btu/yr.

9341 Capital cost for a 10,000 ton/day SRC plant is based on figures in reference (9300). Since the processing of Central coal will require a larger feed the cost of coal preparation, dissolving, filtration, and sulfur recovery have been scaled to reflect the differences in throughput. Additionally, another 1.63E+06 dollars have been added to cover the cost of sour water strippers and activated sludge units. Cost has been escalated from 1969 to 1972 $ using a straight 12 percent increase. Total annualized cost is 8.85E+06 dollars at a 10 percent fixed charge rate. For a plant processing 1.00E+12 Btu/yr, capital cost is 1.22E+05 dollars. Plant load factor is 90 percent.

Operating cost is based on 9.58E+06 dollars and a by-product credit consisting of the following:

Sulfur	1.04E+06 dollars
CO_2	2.65E+05 dollars
Lt Oil	5.13E+04 dollars
Phenol	1.10E+05 dollars
Power	1.18E+05 dollars
Total	2.05E+06 dollars

Costs have been escalated (from 1969) 12 percent to reflect 1972 cost. For a plant processing 1.00E+12 Btu/yr of Central coal, operating costs are 9.44E+04 dollars (9300).

9342 The average haul distance in the Central region is assumed to be 290 miles and the fuel consumption is 0.005 gal/TMI (9335). To haul 1.00E+12 Btu/yr (31500 ton/yr) of SRC, 6.09E+04 gallons are consumed by the 3 locomotives. This assumes a gross to tare weight ratio of 4 to 1. The empty return trip requires 1.52E+04 gallons of diesel fuel. Total fuel consumption to haul 1.00E+12 Btu/yr is 7.61E+04 gallons. Exhaust gases from the three locomotives are as follows (9303,3-7):

	Lb/1000 Gal	Tons/Yr
Particulates	25	0.95
SO_x	65	2.49
CO	70	2.68
HC	50	1.92
NO_x	75	2.88
ALD	4	0.15

In addition, another 12.64 tons/yr of particulates are emitted during loading and unloading (9303,7-2).

9343 Land impacts are based on 290 miles and a 60 foot railway right of way, for a plant processing 10,000 ton/day. The land impact for hauling 6.80E+13 Btu/yr is 2109 acres. For an SRC plant producing 1.00E+12 Btu/yr, the land impact is 31.0 acres.

9345 Primary efficiency for solvent refined coal haulage is 100 percent, assuming negligible losses during transportation.

9346 Ancillary fuel consumption for unit and mixed train haulage is 1.06E+10 Btu/1.00E+12 Btu hauled. From footnote 9342, 7.61E+04 gallons of diesel fuel are consumed. For a heating value of 5.83E+06 Btu/BBL, total energy required is 1.06E+10 Btu.

9347 Freight charges for haulage by unit train are 0.0061 $/TMI (9322,10) in 1969 cost. ICC imposed an 8P and 6P freight rate increase in 1970 and 1971, respectively, to 0.0070 $/TMI. Haulage of 3.15E+04 tons of SRC, equivalent to 1.00E+12 Btu, a distance of 290 miles is 6.39E+04 $ total cost. From (9323,67/70) fixed cost (depreciation only) is about 6P of total annual cost. Hence, fixed cost is 3.83E+03 $ and operating cost is 6.01E+04 $.

9349 The average capacity of a barge is 25000 tons (9326, 35), and the average haul distance is assumed to be 300 miles (the approximate distance from the southern coal fields of Illinois to Chicago via the Illinois River). Air emissions are based on (9303, 3-11). To haul 1.00E+12 Btu of SRC, 1.26 round trips must be made. Air pollutants are as follows:

	Lb/Mi	T/1.00E+12 Btu
Particulates	2	7.58E-01
SO_x	1.5	5.69E-01
CO	1.2	4.55E-01
HC	0.9	3.41E-01
NO_x	1.4	5.31E-01
ALD	0.07	2.65E-02

These pollutants are based on a fuel consumption of 378 Btu per TMI (9325). Another 12.6 tons of particulates are emitted during loading and unloading (9303,7-4).

9350 The cost for shipping coal (SRC) in 1971 by barge was 0.97 dollars per ton (9327,37) of which 12 percent (inclusive of insurance and depreciation) is fixed cost. This agrees with data in (9328,18). Cost to haul 3.15E+04 tons of SRC would be 2.86E+04 dollars operating and 3.91E+03 dollars fixed. Cost is escalated 6 percent to reflect a 1972 base.

VIII. COAL LIQUEFACTION

A. Introduction

The environmental impacts, efficiencies, and costs for the production of low sulfur liquid fuels from coal are given in Table 6 of this report. Data were developed for three regional coals: a high sulfur Central coal, medium sulfur Northern Appalachia coal, and a low sulfur Northwest coal. In addition, a National average case was synthesized from the regional data. The characteristics of the coal and its heat content are specified in the first footnote for each regional case.

Each data entry is based on an energy input of coal equivalent to 10^{12} Btu and has been derived for a "controlled" environmental condition. The nature and magnitude of coal liquefaction operations is such that stringent environmental control must be practiced. A new entry has been included for the truck transportation of coal from the mine to the liquefaction plant. Since the solid waste produced by the liquefaction plant is assumed to be disposed of by returning it to the mine for burial, the truck is no longer empty on its return trip. Hence there is an increased consumption of diesel fuel with a corresponding increase in air pollutants. All of the cost data shown in Table 6 is based on a 90 percent plant load factor, or 328 operating days/yr. The values presented in this table are based on data accumulated during the Spring of 1974.

Two processes were considered for the production of low sulfur liquid fuels from coal. These are the CSF (Consol Synthetic Fuel) and SRC (Solvent Refined Coal) processes. Although other processes are being developed, these two represent the most advanced for which data are readily available. The COED process, although sufficiently advanced, was not considered in this study because, with over half of the output Btu in the form of char or SNG, the process is not set up primarily for the production of liquid fuels.

Table entries have been made both at the process and activity levels for coal liquefaction. The process level entries are representative of the environmental impacts for the CSF and SRC processes, while the activity entry is an average of the process level impacts. An activity level entry was made so as to minimize the differences in process design assumptions, (arising from limited pilot plant data), the degree of completeness, and time periods over which the processes were investigated.

The following sections are brief descriptions of the individual coal conversion processes considered.

1. CSF Process

The CSF process (Figure 24) features extraction of the coal by hydrogenated solvents derived from the coal to produce a liquid-solid slurry. After hydroclave separation, the liquid extract is fractionated in a vacuum still to produce a light fuel oil product and a heavier bottom extract. This extract then passes to a hydrodistillation column from which is taken a naphtha cut and a heavy product fuel oil. The solid residue from the separation step, containing ash plus residual carbon, passes to a carbonization section to remove the remaining solvent. The resulting char from the carbonizer is gasified in a Bigas unit to manufacture the hydrogen required for the entire plant.

2. SRC Process

In the SRC process (Figure 25) coal is dissolved in a recycled solvent under a reducing atmosphere. The resulting liquid-solid phases are separated by means of filtration and the solid phase, containing ash and residual carbonaceous material, is gasified in a Bigas unit to produce the hydrogen required in the hydrotreating units throughout the plant. The liquid phase filtrate passes to a distillation column where it is fractionated to produce a naphtha stream, a distillate, and a residual fuel oil. The naphtha and distillate fractions are subsequently hydrotreated to reduce the sulfur and nitrogen levels of these fuels.

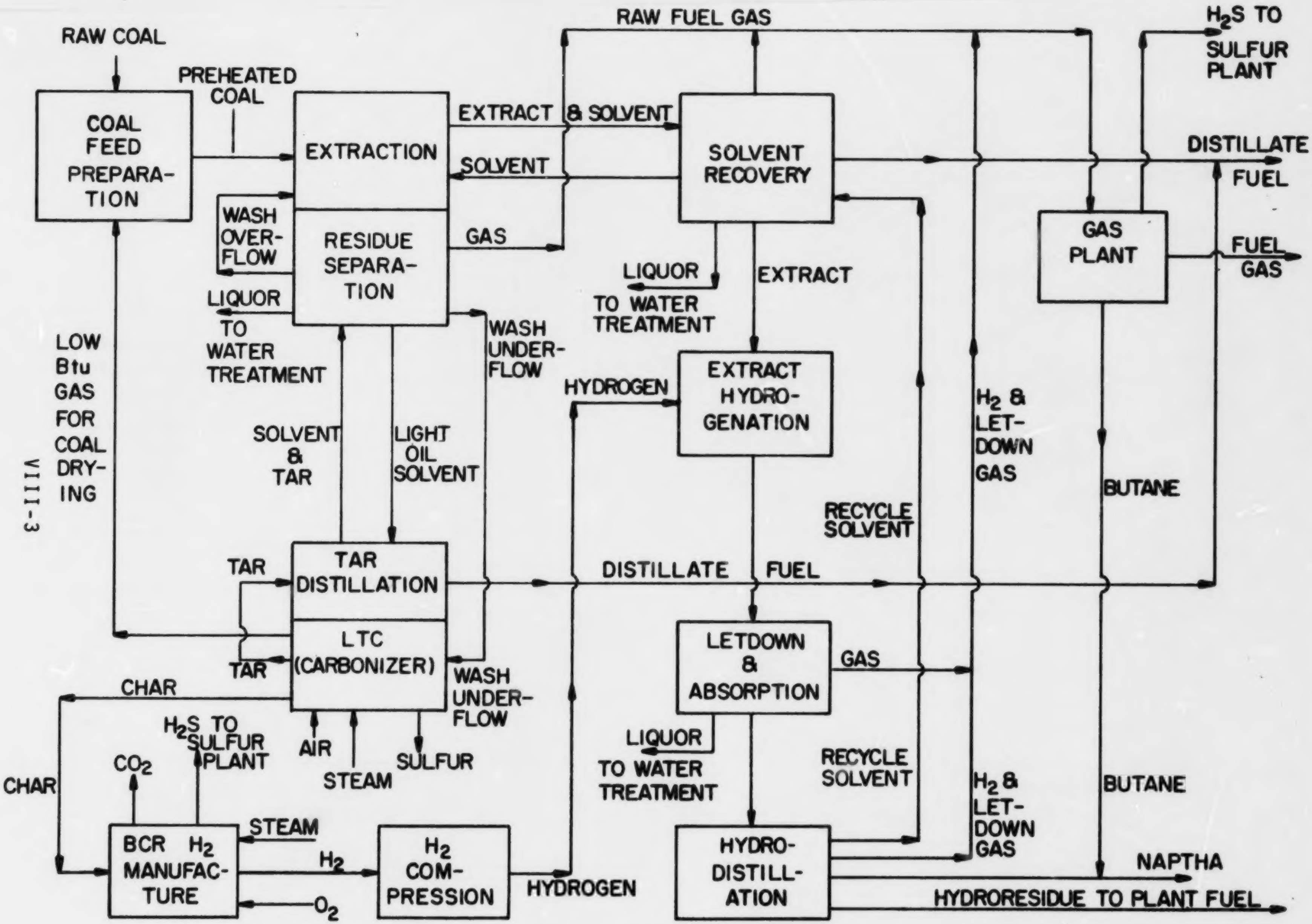
RAW COAL
COAL FEED PREPARATION
PREHEATED COAL
EXTRACTION
RESIDUE SEPARATION
WASH OVERFLOW
LIQUOR TO WATER TREATMENT
LOW Btu GAS FOR COAL DRYING
EXTRACT & SOLVENT
SOLVENT
GAS
WASH UNDERFLOW
SOLVENT & TAR
LIGHT OIL SOLVENT
TAR DISTILLATION
LTC (CARBONIZER)
TAR
TAR
WASH UNDERFLOW
CHAR
CHAR
AIR
STEAM
SULFUR
CO_2
H_2S TO SULFUR PLANT
BCR H_2 MANUFACTURE
STEAM
O_2
H_2
H_2 COMPRESSION
HYDROGEN
HYDROGEN
RAW FUEL GAS
SOLVENT RECOVERY
LIQUOR TO WATER TREATMENT
EXTRACT
EXTRACT HYDROGENATION
DISTILLATE FUEL
LETDOWN & ABSORPTION
GAS
LIQUOR TO WATER TREATMENT
HYDRO-DISTILLATION
RECYCLE SOLVENT
RECYCLE SOLVENT
H_2 & LET-DOWN GAS
H_2 & LET-DOWN GAS
GAS PLANT
BUTANE
BUTANE
H_2S TO SULFUR PLANT
DISTILLATE FUEL
FUEL GAS
NAPTHA
HYDRORESIDUE TO PLANT FUEL

Figure 24. CSF Coal Liquefaction Process (Ref. 9400)

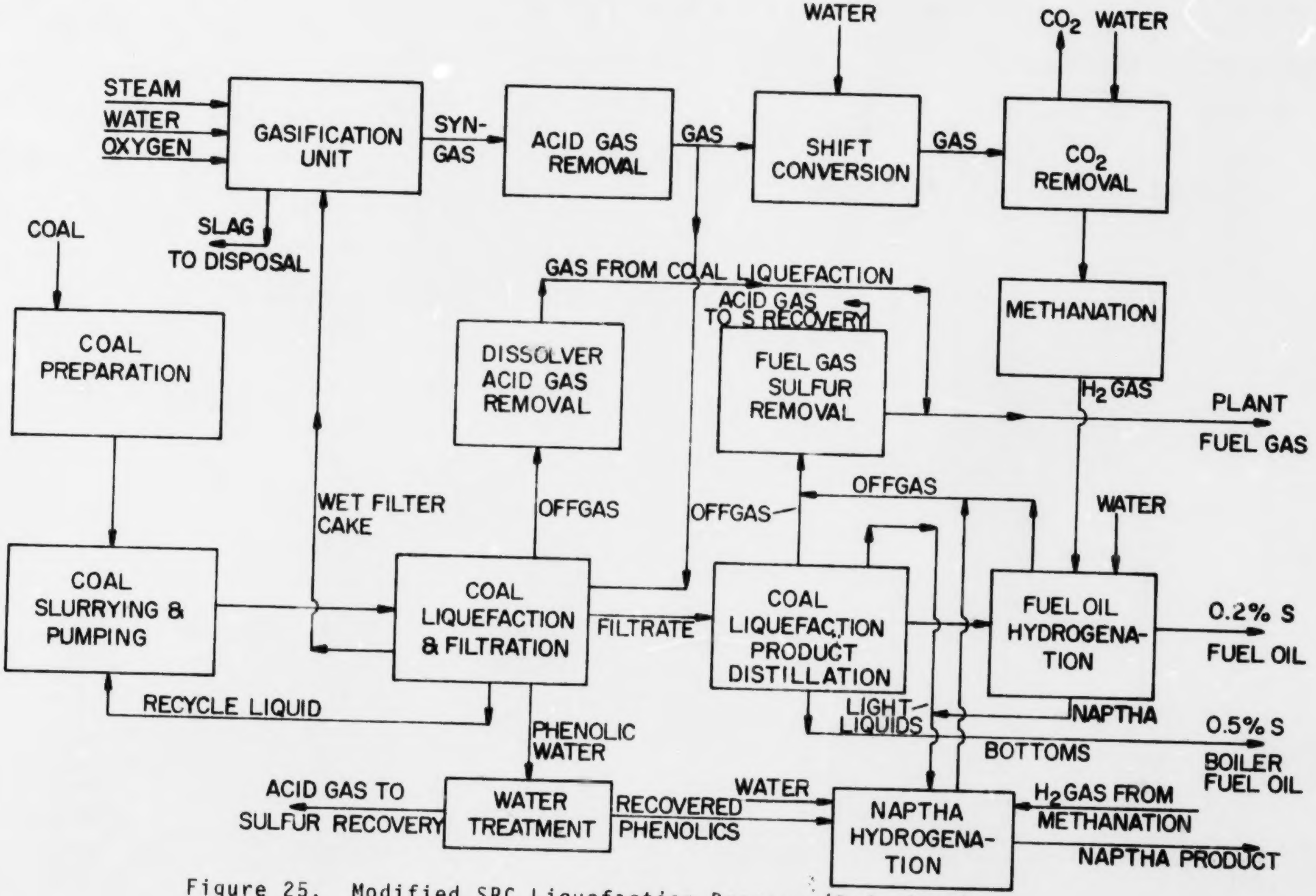
STEAM
WATER
OXYGEN
GASIFICATION UNIT
SLAG TO DISPOSAL
SYN-GAS
ACID GAS REMOVAL
GAS
WATER
SHIFT CONVERSION
GAS
CO2 WATER
CO2 REMOVAL
METHANATION
H2 GAS
PLANT FUEL GAS
COAL
COAL PREPARATION
COAL SLURRYING & PUMPING
RECYCLE LIQUID
WET FILTER CAKE
GAS FROM COAL LIQUEFACTION
DISSOLVER ACID GAS REMOVAL
ACID GAS TO S RECOVERY
FUEL GAS SULFUR REMOVAL
OFFGAS
OFFGAS
OFFGAS
COAL LIQUEFACTION & FILTRATION
FILTRATE
COAL LIQUEFACTION PRODUCT DISTILLATION
WATER
FUEL OIL HYDROGENATION
0.2% S FUEL OIL
NAPTHA
LIGHT LIQUIDS
BOTTOMS
0.5% S BOILER FUEL OIL
PHENOLIC WATER
ACID GAS TO SULFUR RECOVERY
WATER TREATMENT
RECOVERED PHENOLICS
WATER
NAPTHA HYDROGENATION
H2 GAS FROM METHANATION
NAPTHA PRODUCT

Figure 25. Modified SRC Liquefaction Process (Ref. 9401)

B. Impact Data Table and Footnotes

CONTROLLED

FUEL	REGION
COAL	AS INDICATED

ROW	MNE-MON	ACTIVITY PROCESS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			WATER POLLUTANTS (TONS/ 10^{12} BTU, EX COL 12)												AIR		
			ACIDS	BASES	DISSOLVED SOLIDS PO_4	NO_3	OTHER	TOTAL (DS)	SUSPENDED SOLIDS	ORGANICS	TOTAL COL'S 6,7,8	BOD	COD	THERMAL (BTU/10^{12}BTU)	PARTIC-ULATES	NO_x	SO_x
1		NATIONAL AVERAGE															
2	TRNSP	TRANSPORTATION															
3	TRUK	TRUCK	9999	9999	9999	9999	9999	9999	[illegible]	9999	[illegible]	9999	9999	9999	[illegible]	[illegible]	[illegible]
4	LIQFC	LIQUEFACTION	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
5	CSFPR	CSF PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
6	SRCPR	SRC PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
7		NORTHWEST															
8	TRNSP	TRANSPORTATION															
9	TRUK	TRUCK	9999	9999	9999	9999	9999	9999	[illegible]	9999	[illegible]	9999	9999	9999	[illegible]	[illegible]	[illegible]
10	LIQFC	LIQUEFACTION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	CSFPR	CSF PROCESS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	SRCPR	SRC PROCESS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13		CENTRAL															
14	TRNSP	TRANSPORTATION															
15	TRUK	TRUCK	9999	9999	9999	9999	9999	9999	[illegible]	9999	[illegible]	9999	9999	9999	[illegible]	[illegible]	[illegible]
16	LIQFC	LIQUEFACTION	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
17	CSFPR	CSF PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
18	SRCPR	SRC PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
19		NORTHERN APPALACHIA															
20	TRNSP	TRANSPORTATION															
21	TRUK	TRUCK	9999	9999	9999	9999	9999	9999	[illegible]	9999	[illegible]	9999	9999	9999	[illegible]	[illegible]	[illegible]
22	LIQFC	LIQUEFACTION	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
23	CSFPR	CSF PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
24	SRCPR	SRC PROCESS	9999	9999	9999	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]	9999	9999	[illegible]	[illegible]	[illegible]	[illegible]
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12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
	AIR POLLUTANTS (TONS/10^{12} BTU)									OCCUPATIONAL HEALTH						COST (DOLLARS/10^{12} BTU)			
THERMAL BTU/10^{12} BTU	PARTIC-ULATES	NO_x	SO_x	HYDRO-CARBONS	CO	ALDEHYDES ETC.	TOTAL	SOLIDS TONS/10^{12} BTU	LAND (ACRE-YR / 10^{12} BTU)	DEATHS 10^{12} BTU	INJURIES 10^{12} BTU	MAN-DAYS LOST/10^{12} BTU	POTENTIAL LARGE SCALE DISASTER	PRIMARY EFFICIENCY	ANCILLARY ENERGY BTU/10^{12} BTU	FIXED COST	OPERATING COST	TOTAL COST	ROW
																			1
																			2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3
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TABLE 6. ENVIRONMENTAL IMPACTS, EFFICIENCY AND COST FOR ENVIRONMENTALLY CONTROLLED NATIONAL AND REGIONAL COAL LIQUEFACTION

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Footnotes for Table 6

1082 The potential for large scale disasters is non-existent.

1098 Coal losses during haulage from mine to tipple are assumed to be negligible.

1202 The 'haulage' statistics published in (1206) through (1210) were employed here. Haulage encompasses a broad category which includes the following transportation modes for the coal-(1) from an underground mine to the surface by rail and (2) from the surface to the coal preparation plants by truck. No fatalities for hauling coal strip mined in the states of Montana and Wyoming were reported over the years 1964-1966, 1968 and 1969. An average of 0.473 non-fatal injuries/1.0E06 tons production was computed for coal haulage, occurring primarily in Wyoming. An approximate average of 25 work-days lost per injury is assumed for transport following strip mining. This quantity results from averaging the work-days lost/injury for Montana and Wyoming. The basic statistics on average severities were comprised of contributions due to strip mining and haulage. The relative contribution of each cannot be isolated.

1213 No coal is assumed lost between mine and tipple.

1232 To control sedimentation, the runoff from the haul roads is diverted to settling ponds placed at intervals along the roadway (1100). Since the road is relatively short (1.5 mile, footnote 1204) only one settling basin is assumed to be needed. Because of the low rainfall, the settling pond is assumed adequate to contain all the runoff (footnote 1233). The contained water can be utilized for dust suppression of the haul roads or allowed to evaporate.

1233 The haul road land impact is 0.274 AC-yr/1.0E12 Btu (footnote 1204). The settling pond is assumed to have a surface area of 1 AC, which for a depth of 5 feet has a storage capacity of 1.6 MMgal. Thus, the land impact for the settling pond is 0.0285 AC-yr/1.0E12 Btu (2 MMT/yr hauled on roads). The total land impact is 0.303 AC-yr/1.0E12 Btu.

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1358 To control siltation, the runoff from the haul roads is diverted to settling ponds placed along the roadway (1100). It is assumed that all the sediment is removed.

1359 It is assumed that a settling pond is required for each mile of road and that each pond uses an acre of land. Thus, 4 AC are utilized for the settling pond (the haul road is 3.8 mile long, footnote 1312). The land impact is 0.0945 AC-yr/1.0E12 Btu. This is in addition to the land impacted by the road, 0.584 AC-yr/1.0E12 Btu (footnote 1311).

1455 Sediment runoff from coal haulage roads can be controlled by ditching alongside the roads and diverting the runoff to small settling ponds.

1472 It is assumed that a settling pond is required for each mile of road and that each pond uses one acre. Thus seven acres are utilized for the settling ponds (the haul road is 7.3 mile in length, footnote 1415). The land impact is 0.148 AC-yr/1.0E12 Btu. This is in addition to the land impacted by the road, 0.990 AC-yr/1.0E12 Btu (footnote 1415)

2091 Fire and/or explosions caused by gas leaks, oil leaks, act of God, or human error. Possible damage to refinery, personnel, adjacent properties.

9400 The central coal used in this study has the following composition on a run-of-mine basis

		Proximate Analysis-WT PC	
Btu/lb	10820	Ash	11.3
S-WT PC	3.70	Water	14.4
		Vol. Mat.	33.4
		Fixed C	40.9

For this coal 46,200 ton of coal is equivalent to 1.0E12 Btu.

9401 From (9400,13), a plant processing 23364 TPD of ROM coal produces 298.3E09 Btu/D of fuel oil and 62.5E09 Btu/D naphtha or 360.8E09 Btu/D total liquid fuels. The total plant heat demand is 106.4E09 Btu/D, based on (9400,13) plus an additional 14.7E09 Btu/D for previously purchased electricity (61150 Kw). This heat demand is provided by the combustion of fuel gases (89.8E09 Btu/D) and coal (16.6E09 Btu/D). Thus a total of 24,133 TPD coal (522.2E09 Btu/D from footnote 9400) is required to produce the 360.8E09 Btu/D of liquid fuels for a primary efficiency of .691. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

FTN. 9402

9402 The principal quantifiable air pollution sources are as follows

	TPD					
	Part	SO_x	CO	HC	NO_x	Other
Fuels combustion	1.40	8.91	1.11	.157	32.5	.00192
Sulfur recovery plant		3.80				
Storage and misc.				.009		.128

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 769 TPD coal and 89.8E09 Btu/D of gases (containing 0.4 PC of the S in the process feed coal from (9400)). Particulates from the coal fired boiler were reduced 99.5 PC by the use of an ESP and a Wellman Lord wet scrub. SO_2 emissions from the coal fired boiler were reduced 95 PC by the Wellman Lord unit. Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 PC by the use of multiple cyclones and then 99 PC by a baghouse before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine and Rectisol acid gas removal systems in (9400), the Claus plant receives a 55 MOL PC H_2S feed. From (2022,103) this Claus unit can recover 95.5 PC of the incoming S. The incoming S for recovery is based on 23364 TPD process feed coal, 3.70 PC S, and 91.4 PC of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (3.0 PC) and produced as byproduct S (5.2 PC)) from (9400). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 852.2 TPD S is the Claus feed. Thus 813.9 TPD S is recovered from Claus plus 44.3 TPD S from the iron oxide towers for a total of 858.2 TPD S or 1643 ton/1.0E12 Btu. 38.3 TPD S passes to the tailgas unit so that 1.9 TPD S or 3.8 TPD SO_2 exits the stack.

Storage and Misc.

Based on 23364 TPD of process feed coal and 1.1 PC N_2 in the coal (9400,12) and 40 PC of the N_2 as NH_3 (9400, 13), 128 TPD NH_3 is produced and recovered. From (8301, 5.2-2) controlled storage and loading operations emit two lb NH_3/ton NH_3. Thus .128 TPD NH_3 are released into the atmosphere. From (9400,13) 12,200 BBL/D of naphtha are produced. Assuming two weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .009 TPD HC are emitted.

Conversion to tons/1.0E12 Btu is based on a total coal throughput of 24,133 TPD and 46,200 ton coal/1.0E12 Btu.

FTN. 9403-9405

9403 Based on 23,364 TPD process feed coal with 11.3 PC ash, 2645 TPD ash are produced. 95 PC of this is solid waste for disposal with the balance in the products or deposited on catalysts (9400,13). Based on the combustion of 769 TPD coal and .4 TPD of emitted particulates, 86.7 TPD of solid waste is produced. Based on 10,660 GPM net makeup H_2O (9400,51,66) and an assumed 500 PPM suspended solids which is completely removed by lime treatment and clarification, an additional 32 TPD of solid waste is generated. The sum total solid waste produced is thus 2616 TPD or 5007 ton/1.0E12 Btu.

9404 Fixed land requirements are estimated at 500 acres from (9401,7). Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9403) produced is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 500 acres is required for a 24,133 TPD coal liquefaction operation. With a 90 PC operating factor this is equivalent to 2.91 acre-yr/1.0E12 Btu.

9405 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-24,100 TPD, 90 P LF

From (9400,19), escalated from 1971 $ to 1972 $ at 5 PC, costs for coal preparation, extraction, separation, solvent recovery, low temperature carbonization, tar distillation, extract hydroconversion, hydroletdown and absorption, hydrodistillation, gas plant, H_2 manufacture, H_2 compression, and support services total 233.6E06 $. Power generation costs were estimated at 12.8E06 $ from (8323, 42), ESP costs at .16E06 $ from (9402,133), Claus plant costs at 3.7E06 $ from (8303, AI-25), Wellman Lord SO_2 removal costs on coal boiler flue gases at 3.8E06 $ and on Claus tailgases at 3.9E06 $ from (8303, AI-26), and water pollution control costs at 1.8E06 $ from (9400, 102) and (2013,VII-4,VII-5). To the subtotal was added a 7 PC development contingency to arrive at a total plant investment of 278E06 $. Based on a FCR of 10 PC/yr and 7.93E06 TPY coal, this is equivalent to 1.62E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-24,100 TPD, 90 P LF

From (9400,32), costs for catalyst and chemicals, raw water, ash disposal, maintenance material and labor, operating labor, supervision, and payroll and general overhead total 23.64E06 $/year. Operating and maintenance costs on the power boiler were estimated at .19E06 $/year from (1918,46), ESP costs at 5E03 $/year from (9402,135), SGC costs on coal boiler flue gases at .86E06 $/year and on Claus tailgases at .92E06 $/year from (9403,18/27), and water pollution control costs at 45E03 $/year from (2013,VII-4,VII-5). The total gross operating cost is thus 25.66E06 $/year. Byproducts were credited at \$10/LTS (761 LTS/D) and \$25/T NH_3 (128 TPD NH_3) from (8303,AI-5). The total net operating cost is thus 22.11E06 \$/year or, for 7.93E06 TPY coal input, 1.29E05 \$/1.0E12 Btu.

9406 Process wastewater pollutants were derived from (9400) and (9404) and include phenols, cyanide, NH_3, sulfide, oil, and suspended solids. Dissolved solids are contributed by boiler and cooling tower blowdowns and demineralization regenerations. Wastewater treatment includes oil-water separation, dissolved air flotation, ammonia stills, equalization, activated sludge plus clarification, and activated carbon polish. Removal efficiencies were developed from (8318, Table 7), (8313,609,618), (8312,207), (2013,IV-3), and (8316,172). Organics (9.6E-04TPD) comprise phenols and oil, while total dissolved solids includes cyanide (2.2E-03 TPD), NH_3 (.13 TPD), sulfide (9.6E-04 TPD) and other dissolved solids (33.1 TPD). Suspended solids total 4.2E-03 TPD and the process wastewater discharge is 1193 TPD. Conversion to tons/1.0E12 Btu is based on a total coal throughput of 24,133 TPD and 46,200 ton coal/1.0E12 Btu.

9407 From (9401,31) a plant processing 10,000 TPD coal (250.8E09 Btu/D) produces 156.7E09 Btu/D of liquid fuel products for a primary efficiency of .625. Although this is for a different coal, it is assumed that this efficiency holds as well for the central coal (footnote 9400) used in this analysis. Thus, a total of 11,585 TPD of coal is required for the production of 156.7E09 Btu/D of liquid fuels. The total plant heat demand is 76.3E09 Btu/D which is provided for by the combustion of 70E09 Btu/D of fuel gases and 6.3E09 Btu/D of product heavy fuel oil. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

9408 The principal quantifiable air pollution sources are as follows:

	TPD					
	Part	SO_x	CO	HC	NO_x	Other
Fuels combustion	.832	2.40	.626	.0725	22.1	.0196
Sulfur recovery plant		5.0				
Storage and misc.				.0014		.062

Fuels Combustion

Based on air emissions factors in (8301,1.3-2,1.4-2) and the combustion of 6.25E09 Btu/D of heavy fuel oil (containing .28 PC of the S in the process feed coal from

(9405,11)) and 70E09 Btu/d fuel gases (containing negligible S from (9405,11)). Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 percent by the use of multiple cyclones and then 99 percent by a Venturi scrub before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine acid gas removal system in (9405,11, 16,19,21), the Claus plant receives a 10 Mol percent H_2S feed. From (8303,AI-25) this Claus unit can recover 89 percent of the incoming S. The incoming S for recovery is based on 11585 TPD process feed coal, 3.7 percent S, and 94.6 percent of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (5.4 percent)) from (9405,11). Based, furthermore, on complete recycle to Claus of the SO_2 recovered in the Wellman Lord scrubbing unit on the Claus tailgases, 452.8 TPD S is the Claus feed. Thus 403 TPD S is recovered for sale or 1607 ton/1.0E12 Btu. Since 49.8 TPD S passes to the Wellman Lord tailgas scrubbing unit, 2.5 TPD S or 5.0 TPD SO_2 exits to the atmosphere.

Storage and Misc.

Based on 11585 TPD of process feed coal and 1.1 percent N_2 in the coal and the assumption that 40 percent of the N_2 forms NH_3 (9400,13), 61.9 TPD NH_3 is produced and recovered. From (8301,5.2-2) controlled storage and loading operations emit 2 lb NH_3/ton NH_3. Thus .062 TPD NH_3 are released into the atmosphere. From (9405,11) 2011 BBL/D of naphtha are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted.
Conversion to tons/1.0E12 Btu is based on a total coal throughput of 11585 TPD and 46200 ton coal/1.0E12 Btu.

9409 Based on 11585 TPD process feed coal with 11.3 percent ash, 1311 TPD ash are produced. Based on 3626 gpm net makeup H_2O (9401,27) and an assumed 500 ppm suspended solids which is completely removed by lime treatment and clarification, an additional 11 TPD of solid waste is generated. The sum total solid waste produced is thus 1322 TPD or 5272 ton/1.0E12 Btu.

9410 Fixed land requirements are estimated at 280 acres from (9405,48). Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9409) produced is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 280 acres is required for a 11585 TPD coal liquefaction operation. With a 90 percent operating factor this is equivalent to 3.40 acre-yr/1.0E12 Btu.

9411 Capital and operating costs were developed as follows:

Capital Costs-1972 \$-Plant Basis-11,600 TPD, 90 P LF

From (9401,57), deescalated from 1973 to 1972 \$ at 5 percent, costs for coal preparation, coal slurrying and pumping, coal liquefaction and filtration, dissolver acid gas removal, coal liquefaction product distillation, fuel oil hydrogenation, naphtha hydrogenation, fuel gas sulfur removal, gasification, acid gas removal, shift conversion, CO_2 removal, methanation, O_2 plant, instrument and plant air, raw H_2O treatment, process waste H_2O treatment, power generation, product storage, slag removal system, steam generation, general facilities, and home office engineering total 207E06 \$. Claus plant costs were estimated at 3.3E06 \$ from (8303,AI-25), Wellman Lord SO_2 removal costs on Claus tailgases at 4.5E06 \$ from (8303,AI-26), carbon absorption for wastewater costs at .25E06 \$ from (2013,VII-4), and a Venturi for particulate removal on the thermal dryer at .40E06 \$ from (1080,64). The total plant investment is thus 215.5E06 \$. Based on a FCR of 10 percent/yr and 3.81E06 TPY coal this is equivalent to 2.61E05 \$/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-11,600 TPD, 90 P LF

From (9406) the preliminary estimated operating costs of a 10,000 T/D plant are 50E06 \$/yr based on \$9/ton coal. Assuming a 90 percent operating factor this would give 29.6E06 \$/yr for coal cost and 20.4E06 \$/yr for other operating expenses. Based on 20.4 E06 \$/yr and 3.81E06 TPY coal this becomes 2.47E05 \$/1.0E12 Btu.

9412 Process waste water pollutants were derived from (9300) and (9313,61) and included phenols, cyanide, NH_3, sulfide, oil, and suspended solids. Dissolved solids are contributed by boiler and cooling tower blowdowns and demineralization regenerations. Waste water treatment includes oil-H_2O separation, phenol solvent extraction, sour H_2O stripping, primary clarification, activated sludge, secondary clarification, and activated carbon polish. Removal efficiencies were developed from (8318, Table 7), (9301), (8322), (9305), and (9311). Organics (7.9E-04 TPD) comprise phenols and oil, while total dissolved solids includes cyanide (1.1E-02 TPD), NH_3 (.01 TPD), sulfide (3E-03 TPD) and other dissolved solids (13.1 TPD). Suspended solids total 4.4E-03 TPD and the process waste H_2O discharge is 208 TPD. Conversion to tons/1.0E12 Btu is based on a total coal throughput of 11585 TPD and 46200 ton coal/1.0E12 Btu.

9413 Thermal discharges can be completely eliminated by the use of mechanical draft wet cooling towers.

9414 In 1969 the average truck capacity for this region was 59 T and the average haulage distance from mine to tipple was 3.8 mi (0001,344). The fuel consumption rate is assumed to be 7 gal/1000 TMI (0002,3-7) and the gross to tare weight ratio of the trucks is assumed to be 2.5 to 1. Based on 46200 ton coal/1.0E12 Btu, 783 round trips are required to deliver 1.0E12 Btu. From footnotes 9403 and 9409 the liquefaction plant produces an average of 5140 ton solid waste, so that 6.6 ton of solid waste/return trip goes back to the mine. Thus a round trip is 548 ton miles and 3003 gal of diesel fuel are consumed/1.0E12 Btu. Emissions from a diesel powered truck are given in (0002,3-7). Dusting from haulage roads is controlled by watering down, oiling, or some other method.

9415 The Northern Appalachian coal used in this study has the following composition on a run-of-mine basis

		Proximate Analysis-Wt. Pc.	
Btu/lb	12000	Ash	10.0
S-Wt Pc	2.0	Water	5.0
		Vol.Mat.and Fixed C.	85.0

For this coal 41700 ton of coal is equivalent to 1.0E12 Btu.

9416 From (9400,13) a plant processing 23364 TPD of ROM coal produces 360.8E09 Btu/d liquid fuel products. The total plant heat demand is 106.4E09 Btu/d, based on (9400,13) plus an additional 14.7E09 Btu/d for previously purchased electricity (61150 Kw). This heat demand is provided by the combustion of fuel gases (89.8E09 Btu/d) and coal (16.6E09 Btu/d). Thus a total of 24133 TPD coal is required to produce the 360.8E09 Btu/d of liquid fuels for a primary efficiency of .691. Although this is for a different coal, it is assumed that this efficiency holds as well for the Northern Appalachian coal (footnote 9415) used in this analysis. Thus 21067 TPD coal is required for process feed and 692 TPD coal is used in boilers for a total of 21759 TPD coal. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

9417 The principal quantifiable air pollution sources are as follows

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.37	2.84	1.07	.146	31.8	.00173
Sulfur Recovery Plant		2.0				
Storage and Misc.				.009		.113

Fuels Combustion

Based on air emissions factors in (8301,1.1-3,1.4-2) and the combustion of 692 TPD coal and 89.7E09 Btu/d of gases (containing 0.4 percent of the S in the process feed coal from (9400)). Particulates from the coal fired boiler were reduced 99.5 percent by the use of an ESP and a Wellman Lord wet scrub. SO_2 emissions from the coal-fired boiler were reduced 95 percent by the Wellman Lord unit. Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 percent by the use of muitiple cyclones and then 99 percent by a bag house before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine and Rectisol acid gas removal systems in (9400), the Claus plant receives a 43 Mol percent H_2S feed. From (2022,103) this Claus unit can recover 94.9 percent of the incoming S. The incoming S for recovery is based on 21067 TPD process feed coal, 2.0 percent S, and 91.4 percent of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (3.0 percent) and produced as by-product S (5.2 percent)) from (9400). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 413.1 TPD S is the Claus feed. Thus 392 TPD S is recovered from Claus plus 21.9 TPD S from the iron oxide towers for a total of 414 TPD S or 793 ton/1.0E12 Btu. Since 21.1 TPD S passes to the Wellman Lord tailgas scrubbing unit, 1.0 TPD S or 2.0 TPD SO_2 exits the stack.

Storage and Misc.

Based on 21067 TPD of process feed coal and 1.1 percent N_2 in the coal and 40 percent of the N_2 as NH_3 (9400,13), 113 TPD NH_3 is produced and recovered. From (8301,5.2-2) controlled storage and loading operations emit 2 lb NH_3/ton NH_3. Thus .113 TPD NH_3 are released into the atmos-

phere. From (9400,13) 12200 BBL/d of naphtha are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .009 TPD HC are emitted.
Conversion to tons/1.0E12 Btu is based on a total coal throughput of 21759 TPD and 41700 ton coal/1.0E12 Btu.

9418 Based on 21067 TPD process feed coal with 10 percent ash, 2107 TPD ash are produced. 95 percent of this is solid waste for disposal with the balance in the products or deposited on catalysts (9400,13). Based on the combustion of 692 TPD coal and .4 TPD of emitted particulates, 68.8 TPD of solid waste is produced. Based on 10660 gpm net makeup H_2O (9400,51,66) and an assumed 500 ppm suspended solids which is completely removed by lime treatment and clarification, an additional 32 TPD of solid waste is generated. The sum total solid waste produced is thus 2090 TPD or 4004 ton/1.0E12 Btu.

9419 Fixed land requirements are estimated at 500 acres from (9401,7). Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9418) produced is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 500 acres is required for a 21759 TPD coal liquefaction operation. With a 90 percent operating factor this is equivalent to 2.92 acre-yr/1.0E12 Btu

9420 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-21,800 TPD, 90 P LF

From (9400,19), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal preparation, extraction, separation, solvent recovery, low temperature carbonization, tar distillation, extract hydroconversion, hydroletdown and absorption, hydrodistillation, gas plant, H_2 manufacture, H_2 compression, and support services total 233.6E06 $. Power generation costs were estimated at 12.8E06 $ from (8323,42), ESP costs at .16E06 $ from (9402,133), Claus plant costs at 2.3E06 $ from (8303, AI-25), Wellman Lord SO_2 removal costs on coal boiler flue gases at 2.8E06 $ and on Claus tailgases at 2.8E06 $ from (8303,AI-26), and H_2O pollution control costs at 1.8E06 $ from (9400,102) and (2013,VII-4,VII-5). To the subtotal was added a 7 percent development contingency to arrive at a total plant investment of 274.3E06 $. Based on a FCR of 10 percent/yr and 7.15E06 TPY coal this is equivalent to 1.60E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-21,800 TPD, 90 P LF

From (9400,32) costs for catalyst and chemicals, raw H_2O, ash disposal, maint. mat. and labor, operating labor, supv., and payroll and gen. overhead total 23.33E06 $/Yr. Operating and maintenance costs on the power boiler were estimated at .19E06 $/yr from (1918, 46), ESP costs at 5E03 $/yr from (9402,135), SGC costs on coal boiler flue gases at .63E06 $/yr and on Claus tailgases at .66E06 $/yr from (9403,18/27), and H_2O pollution control costs at 45E03 $/yr from (2013,VII-4, VII-5). The total gross operating cost is thus 24.86E06 $/yr. By-products were credited at $10/LTS (369 LTS/D) and $25/T NH_3 (113 TPD NH_3) from (8303,AI-5). The total net operating cost is thus 22.73E06 $/yr or, for 7.15E06 TPY coal input, 1.33E05 $/1.0E12 Btu.

9421 Process waste water pollutants were derived from (9400) and (9404) and included phenols, cyanide, NH_3, sulfide, oil, and suspended solids. Dissolved solids are contributed by boiler and cooling tower blowdowns and demineralization regenerations. Waste H_2O treatment includes oil-H_2O separation, dissolved air flotation, ammonia stills, equalization, activated sludge plus clarification, and activated carbon polish. Removal efficiencies were developed from (8318,Table 7), (8313, 609,618), (8312,207), (2013,IV-3), and (8316,172). Organics (9.6E-04 TPD) comprise phenols and oil, while total dissolved solids includes cyanide (2.2E-03 TPD), NH_3 (.13 TPD), sulfide (9.6E-04 TPD) and other dissolved solids (33.1 TPD). Suspended solids total 4.2E-03 TPD and the process waste H_2O discharge is 1193 TPD. Conversion to tons/1.0E12 Btu is based on a total coal throughput of 21759 TPD and 41700 ton coal/ 1.0E12 Btu.

9422 From (9401,31) a plant processing 10000 TPD coal (250.8E09 Btu/D) produces 156.7E09 Btu/D of liquid fuel products for a primary efficiency of .625. Although this is for a different coal, it is assumed that this efficiency holds as well for the N. Appalachian coal (footnote 9415) used in this analysis. Thus a total of 10446 TPD of coal is required for the production of 156.7E09 Btu/D of liquid fuels. The total plant heat demand is 76.3E09 Btu/D which is provided for by the combustion of 70E09 Btu/D of fuel gases and 6.3E09 Btu/D of product heavy fuel oil. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

FTN. 9423

9423 The principal quantifiable air pollution sources are as follows:

TPD

	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	.815	1.17	.626	.0725	22.1	.0196
Sulfur Recovery Plant		2.4				
Storage and Misc.				.0014		.056

Fuels Combustion

Based on air emissions factors in (8301,1.3-2,1.4-2) and the combustion of 6.25E09 Btu/D of heavy fuel oil (containing .28 percent of the S in the process feed coal from (9405,11)) and 70E09 Btu/D of fuel gases (containing negligible S from (9405,11)). Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 percent by the use of multiple cyclones and then 99 percent by a Venturi scrub before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine acid gas removal system in (9405,11, 16,19,21), the Claus plant receives a 10 Mol percent H_2S feed. From (8303,AI-25) this Claus unit can recover 89 percent of the incoming S. The incoming S for recovery is based on 10446 TPD process feed coal, 2.0 percent S, and 94.6 percent of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (5.4 percent)) from (9405,11). Based, furthermore, on complete recycle to Claus of the SO_2 recovered in the Wellman Lord scrubbing unit on the Claus tailgases, 220.6 TPD S is the Claus feed. Thus 196.3 TPD S is recovered for sale or 783 ton/1.0E12 Btu. Since 24.3 TPD S passes to the Wellman Lord tailgas scrubbing unit, 1.2 TPD S or 2.4 TPD SO_2 exits to the atmosphere.

Storage and Misc.

Based on 10446 TPD of process feed coal and 1.1 percent N_2 in the coal and the assumption that 40 percent of the N_2 forms NH_3 (9400,13), 55.8 TPD NH_3 is produced and recovered. From (8301,5.2-2) controlled storage and loading operations emit 2 lb NH_3/ton NH_3. Thus .056 TPD NH_3 are released into the atmosphere. From (9405,11) 2011 BBL/d of naphtha are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted.
Conversion to tons/1.0E12 Btu is based on a total coal throughput of 10446 TPD and 41700 ton coal/1.0E12 Btu.

9424 Based on 10466 TPD process feed coal with 10.0 percent ash, 1045 TPD ash are produced. Based on 3626 gpm net makeup H_2O (9401,27) and an assumed 500 ppm suspended solids which is completely removed by lime treatment and clarification, an additional 11 TPD of solid waste is generated. The sum total solid waste produced is thus 1056 TPD or 4214 ton/1.0 E12 Btu.

9425 Fixed land requirements are estimated at 280 acres from (9405,48). Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9424) produced is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 280 acres is required for a 10446 TPD coal liquefaction operation. With a 90 percent operating factor this is equivalent to 3.40 acre-yr/1.0E12 Btu.

9426 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-10,400 TPD, 90 P LF

From (9401,57), de-escalated from 1973 to 1972 $ at 5 percent, costs for coal preparation, coal slurrying and pumping, coal liquefaction and filtration, dissolver acid gas removal, coal liquefaction product distillation, fuel oil hydrogenation, naphtha hydrogenation, fuel gas sulfur removal, gasification, acid gas removal, shift conversion, CO_2 removal, methanation, O_2 plant, instrument and plant air, raw H_2O treatment, process waste H_2O treatment, power generation, product storage, slag removal system, steam generation, general facilities, and home office engineering total 207E06 $. Claus plant costs were estimated at 1.9E06 $ from (8303,AI-25), Wellman Lord SO_2 removal costs on Claus tailgases at 3.2E06 $ from (8303,AI-26), carbon absorption for wastewater costs at .25E06 $ from (2013,VII-4), and a Venturi for particulate removal on the thermal dryer at .40E06 $ from (1080,64). The total plant investment is thus 212.7E06 $. Based on a FCR of 10 percent/yr and 3.43E06 TPY coal this is equivalent to 2.59E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-10,400 TPD, 90 P LF

From (9406) the preliminary estimated operating costs are 50E06 $/yr based on $9/ton coal. Assuming a 90 percent operating factor this would give 29.6E06 $/yr for coal cost and 20.4E06 $/yr for other operating expenses. Based on 20.4E06 $/yr and 3.43E06 TPY coal this becomes 2.48E05 $/1.0E12 Btu.

9427 Process waste water pollutants were derived from (9300) and (9313,61) and included phenols, cyanide, NH_3, sulfide, oil, and suspended solids. Dissolved solids are contributed by boiler and cooling tower blowdowns and demineralization regenerations. Waste water treatment includes oil-H_2O separation, phenol solvent extraction, sour H_2O stripping, primary clarification, activated sludge, secondary clarification, and activated carbon polish. Removal efficiencies were developed from (8318, Table 7), (9301), (8322), (9305), and (9311). Organics (7.9E-04 TPD) comprise phenols and oil, while total dissolved solids includes cyanide (1.1E-02 TPD), NH_3 (.01 TPD), sulfide (3E-03 TPD) and other dissolved solids (13.1 TPD). Suspended solids total 4.4E-03 TPD and the process waste H_2O discharge is 208 TPD. Conversion to tons/1.0E12 Btu is based on a total coal throughput of 10446 TPD and 41700 ton coal/1.0E12 Btu.

9428 In 1969 the average truck capacity for this region was 22T and the average haulage distance from mine to tipple was 7.3 mi (0001,344). The fuel consumption rate is assumed to be 7 gal/1000 TMI(0002,3-7) and the gross to tare weight ratio of the trucks is assumed to be 2.5 to 1. Based on 41700 ton coal/1.0E12 Btu, 1895 round trips are required to deliver 1.0E12 Btu. From footnotes 9418 and 9424, the liquefaction plant produces an average of 4110 ton solid waste, so that 2.2 ton of solid waste/return trip goes back to the mine. Thus a round trip is 391 ton-miles and 5191 gal of diesel fuel are consumed/1.0E12 Btu. Emissions from a diesel powered truck are given in (0002,3-7). Dusting from haulage roads is controlled by watering down, oiling, or some other method.

9429 Fuel consumption by the haulage trucks amounts to 5191 gal diesel fuel/1.0E12 Btu (footnote 9428). For 5.83E06 Btu/BBL diesel fuel this is equivalent to 7.21E08 Btu/1.0E12 Btu.

9430 The Northwest coal used in this study has the following composition on a run-of-mine basis

		Proximate Analysis-Wt.Pc.	
Btu/lb	8806	Ash	6.0
S-Wt.Pc.	0.5	H_2O	22.0
		Vol.Mat.	29.4
		Fixed C.	42.6

For this coal 57000 ton of coal is equivalent to 1.0E12 Btu.

9431 From (9400,13) a plant processing 23364 TPD of ROM coal produces 360.8E09 Btu/D liquid fuel products. The total plant heat demand is 106.4E09 Btu/D, based on (9400,13) plus an additional 14.7E09 Btu/D for previously purchased electricity (61150 Kw). This heat demand is provided by the combustion of fuel gases (89.8E09 Btu/D) and coal (16.6E09 Btu/D). Thus a total of 24133 TPD coal is required to produce the 360.8E09 Btu/D of liquid fuels for a primary efficiency of .691. Although this is for a different coal, it is assumed that this efficiency holds as well for the subbituminous Northwest coal (footnote 9430) used in this analysis. Thus 28696 TPD coal is required for process feed and 949 TPD coal is used in boilers for a total of 29645 TPD coal. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

9432 The principal quantifiable air pollution sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	1.24	1.53	1.08	.147	31.9	.00174
Sulfur Recovery Plant		0.80				
Storage and Misc.				.009		.098

Fuels Combustion

Based on air emission factors in (8301,1.1-3,1.4-2) and the combustion of 696 equivalent TPD coal and 89.7E09 Btu/D of gases (containing 0.4 percent of the S in the process feed coal from (9400)). Particulates from the coal fired boiler were reduced 99.5 percent by the use of an ESP and a Wellman Lord wet scrub. SO_2 emissions from the coal fired boiler were reduced 95 percent by the Wellman Lord unit. Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 percent by the use of multiple cyclones and then 99 percent by a bag house before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine and Rectisol acid gas removal systems in (9400), the Claus plant receives a 35 Mol percent H_2S feed. From (2022,103) this Claus unit can recover 94.6 percent of the incoming S. The incoming S for recovery is based on 28696 TPD process feed coal, 0.5 percent S, and 91.4 percent of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (3.0 percent) and produced as by-product S (5.2 percent)) from (9400). Based, furthermore, on complete recycle to Claus of all the SO_2 recovered in the Wellman Lord scrubbing units on the boiler flue gases and Claus tailgases, 141.4 TPD S is the Claus feed. Thus 133.8 TPD S is recovered from Claus plus 8 TPD S from the iron oxide towers for a total of 142 TPD S or 273 ton/1.0E12 Btu. Since 7.6 TPD S passes to the Wellman Lord tailgas scrubbing unit, 0.4 TPD S or 0.8 TPD SO_2 exits the stack.

Storage and Misc.

Based on 28696 TPD of process feed coal and 0.7 percent N_2 in the coal and 40 percent of the N_2 as NH_3 (9400,13), 97.5 TPD NH_3 is produced and recovered. From (8301,5.2-2) controlled storage and loading operations emit 2 lb NH_3/ton NH_3. Thus .098 TPD NH_3 are released into the atmosphere. From (9400,13) 12200 BBL/D of naphtha are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .009 TPD HC are emitted.
Conversion to tons/1.0E12 Btu is based on a total coal throughput of 29645 TPD and 57000 ton coal/1.0E12 Btu.

9433 Based on 28696 TPD process feed coal with 6 percent ash, 1722 TPD ash are produced. 95 percent of this is solid waste for disposal with the balance in the products or deposited on catalysts (9400,13). Based on the combustion of 949 TPD coal and .2 TPD of emitted particulates, 56.7 TPD of solid waste is produced. Based on the assumption that H_2O requirements for this plant can be cut in half through the use of air cooling, 5330 gpm net makeup H_2O would be required. Assuming 500 ppm suspended solids in this H_2O and complete removal by lime treatment and clarification, an additional 16 TPD of solid waste is generated. The sum total solid waste produced is thus 1698 TPD or 3264 ton/1.0E12 Btu.

9434 Fixed land requirements are estimated at 500 acres for coal storage, preparation, and liquefaction plant facilities from (9401,7) and at 265 acres for evaporation ponds to handle the concentrated dissolved solids streams. Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9433) produced is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 765 acres is required for a 29645 TPD coal liquefaction operation. With a 90 percent operating factor this is equivalent to 4.48 acre-yr/1.0E12 Btu.

9435 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-29,600 TPD, 90 P LF

From (9400,19), escalated from 1971 $ to 1972 $ at 5 percent, costs for coal preparation, extraction, separation, solvent recovery, low temperature carbonization, tar distillation, extract hydroconversion, hydroletdown and absorption, hydrodistillation, gas plant, H_2 manufacture, H_2 compression, and support services total 233.6E06 \$. Power generation costs were estimated at 12.8E06 \$ from (8323,42), ESP costs at .16E06 \$ from (9402,133), Claus plant costs at 1.0E06 \$ from (8303,AI-25), Wellman Lord SO_2 removal costs on coal boiler flue gases at 1.9E06 \$ and on Claus tailgases at 1.5E06 \$ from (8303,AI-26), and H_2O pollution control costs at 1.8E06 \$ from (9400,102) and (2013,VII-4,VII-5). To the subtotal was added a 7 percent development contingency to arrive at a total plant investment of 270.7E06 \$. Based on a FCR of 10 percent/yr and 9.74E06 TPY coal this is equivalent to 1.58E05 \$/1.0E12 Btu.

Operating Costs-1972 \$-Plant Basis-29,600 TPD, 90 P LF

From (9400,32) costs for catalyst and chemicals, raw H_2O, ash disposal, maint. mat. and labor, operating labor, super., and payroll and general overhead total 22.85E06 \$/yr. Operating and maintenance costs on the power boiler were estimated at .19E06 \$/yr from (1918, 46), ESP costs at 5E03 \$/yr from (9402,135), SGC costs on coal boiler flue gases at .49E06 \$/yr and on Claus tailgases at .42E06 \$/yr from (9403,18/27), and H_2O pollution control costs at 45E03 \$/yr from (2013,VII-4, VII-5). The total gross operating cost is thus 23.99E06 \$/yr. By-products were credited at \$10/LTS (126 LTS/D) and \$25/T NH_3 (98 TPD NH_3) from (8303,AI-5). The total net operating cost is thus 22.78E06 \$/yr or for 9.74E06 TPY coal input, 1.33E05 \$/1.0E12 Btu.

9436 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste H_2O and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

9437 From (9401,31) a plant processing 10000 TPD coal (250.8E09 Btu/D) produces 156.7E09 Btu/D of liquid fuel products for a primary efficiency of .625. Although this is for a different coal, it is assumed that this efficiency holds as well for Northwest coal (footnote 9430) used in this analysis. Thus a total of 14235 TPD of coal is required for the production of 156.7E09 Btu/D of liquid fuels. The total plant heat demand is 76.3E09 Btu/D which is provided for by the combustion of 70E09 Btu/D of fuel gases and 6.3E09 Btu/D of product heavy fuel oil. The ancillary energy is zero because the plant is self-sustaining with all power and steam requirements generated on-site.

9438 The principal quantifiable air pollution sources are as follows:

	TPD					
	Part.	SO_x	CO	HC	NO_x	Other
Fuels Combustion	.872	0.40	.626	.0725	22.1	.0196
Sulfur Recovery Plant		0.80				
Storage and Misc.				.0014		.048

Fuels Combustion

Based on air emissions factors in (8301,1.3-2,1.4-2) and the combustion of 6.25E09 Btu/D of heavy fuel oil (containing .28 percent of the S in the process feed coal from (9405,11)) and 70E09 Btu/D fuel gases (containing negligible S from (9405,11)). Particulate emissions from the coal thermal dryers are based on (8301,8.9-1). These emissions are reduced 85 percent by the use of multiple cyclones and then 99 percent by a Venturi scrub before entering the atmosphere.

Sulfur Recovery Plant

Based on the amine acid gas removal system in (9405,11, 16,19,21), the Claus plant receives a 10 Mol percent H_2S feed. From (8303,AI-25) this Claus unit can recover 89 percent of the incoming S. The incoming S for recovery is based on 14235 TPD process feed coal, 0.5 percent S, and 94.6 percent of the feed S as H_2S to Claus for recovery (the balance of the S is in the liquid fuel products (5.4 percent)) from (9405,11). Based, furthermore, on complete recycle to Claus of the SO_2 recovered in the Wellman Lord scrubbing unit on the Claus tailgases, 75.3 TPD S is the Claus feed. Thus 67.0 TPD S is recovered for sale or 268 ton/1.0E12 Btu. Since 8.3 TPD S passes to the Wellman Lord tailgas scrubbing unit, 0.4 TPD S or 0.8 TPD SO_2 exits to the atmosphere.

Storage and Misc.

Based on 14235 TPD of process feed coal and 0.7 percent N_2 in the coal, and the assumption that 40 percent of the N_2 forms NH_3 (9400,13), 48.4 TPD NH_3 is produced and recovered. From (8301,5.2-2) controlled storage and loading operations emit 2 lb NH_3/ton NH_3. Thus .048 TPD NH_3 are released into the atmosphere. From (9405,11) 2011 BBL/D of naphtha are produced. Assuming 2 weeks storage capacity under new tank conditions and emission factors from (8302,4.3-8), .001 TPD HC are emitted. Conversion to tons/1.0E12 Btu is based on a total coal throughput of 14235 TPD and 57000 ton coal/1.0E12 Btu.

9439 Based on 14235 TPD process feed coal with 6.0 percent ash, 854 TPD ash are produced. Based on 3626 gpm net makeup H_2O (9401,27) and an assumed 500 ppm suspended solids which is completely removed by lime treatment and clarification, an additional 11 TPD of solid waste is generated. The sum total solid waste produced is thus 865 TPD or 3464 ton/1.0E12 Btu.

9440 Fixed land requirements are estimated at 280 acres for coal storage, preparation, and liquefaction plant facilities from (9405,48) and at 230 acres for evaporation ponds to handle the concentrated dissolved solids streams. Since coal liquefaction is considered a mine-mouth activity, all solid waste (Footnote 9439) is assumed to be returned to the mine for burial. There is, therefore, no incremental land impact due to solid waste production. Thus a total of 510 acres is required for a 14235 TPD coal liquefaction operation. With a 90 percent operating factor this is equivalent to 6.22 acre-yr/1.0E12 Btu.

9441 Capital and operating costs were developed as follows:

Capital Costs-1972 $-Plant Basis-14,200 TPD, 90 P LF

From (9401,57), de-escalated from 1973 to 1972 $ at 5 percent, costs for coal preparation, coal slurrying and pumping, coal liquefaction and filtration, dissolver acid gas removal, coal liquefaction product distillation, fuel oil hydrogenation, naphtha hydrogenation, fuel gas sulfur removal, gasification, acid gas removal, shift conversion, CO_2 removal, methanation, O_2 plant, instrument and plant air, raw H_2O treatment, process waste H_2O treatment, power generation, product storage, slag removal system, steam generation, general facilities, and home office engineering total 207E06 $. Claus plant costs were estimated at .87E06 $ from (8303,AI-25), Wellman Lord SO_2 removal costs on Claus tailgases at 2.0E06 $ from (8303,AI-26), carbon absorption for waste water costs at .25E06 $ from (2013,VII-4), and a Venturi for particulate removal on the thermal dryer at .40E06 $ from (1080,64). The total plant investment is thus 210.5E06 $. Based on a FCR of 10 percent/yr and 4.68E06 TPY coal this is equivalent to 2.56E05 $/1.0E12 Btu.

Operating Costs-1972 $-Plant Basis-14,200 TPD, 90 P LF

From (9406) the preliminary estimated operating costs are 50E06 $/yr based on $9/ton coal. Assuming a 90 percent operating factor this would give 29.6E06 $/yr for coal cost and 20.4E06 $/yr for other operating expenses. Based on 20.4E06 $/yr and 4.68E06 TPY coal this becomes 2.48E05 $/1.0E12 Btu.

9442 Water pollutants are zero because there is no aqueous discharge from the boundaries of the plant operation. All process waste H_2O and impounded runoff is treated and used for cooling tower makeup, while all blowdown streams are collected and sent to lined evaporative ponds for disposal.

9443 Based on the use of 100 T truck capacity and an average haulage distance from mine to tipple of 1.5 miles (0001, 344). The fuel consumption rate is assumed to be 7 gal/ 1000 TMI (0002,3-7) and the gross to tare weight ratio of the trucks is assumed to be 2.5 to 1. Based on 57000 ton coal/1.0E12 Btu, 570 round trips are required to deliver 1.0E12 Btu. From footnotes 9433 and 9439 the liquefaction plant produces an average of 3360 T solid waste, so that 5.9 T of solid waste/return trip goes back to the mine. Thus a round trip is 359 ton miles and 1432 gal of diesel fuel are consumed/1.0E12 Btu. Emissions from a diesel powered truck are given in (0002,3-7). Dusting from haulage roads is controlled by watering down, oiling, or some other method.

9444 Fuel consumption by the haulage trucks amounts to 1432 gal diesel fuel/1.0E12 Btu (footnote 9443). For 5.83E06 Btu/BBL diesel fuel this is equivalent to 1.99E08 Btu/ 1.0E12 Btu.

9445 The primary efficiency and ancillary energy for this process are the arithmetic average of the primary efficiency and ancillary energy for the Northern Appalachian, Central, and Northwest regions.

9446 Air pollutants for this process are the arithmetic average of the air pollutants for the Northern Appalachian, Central, and Northwest regions.

9447 Solid waste for this process is the arithmetic average of the solid waste produced in the Northern Appalachian, Central, and Northwest regions.

9448 Land utilized by this process is the arithmetic average of the land used in the Northern Appalachian, Central, and Northwest regions.

9449 Capital and operating costs for this process are the arithmetic average of the capital and operating costs for the Northern Appalachian, Central, and Northwest regions.

9450 Water pollutants for this process are the arithmetic average of the water pollutants for the Northern Appalachian, Central, and Northwest regions.

9451 Thermal discharges for this process are the arithmetic average of thermal discharges for the Northern Appalachian, Central, and Northwest regions.

9452 From footnote 1046 the capital cost of transportation equipment for a 2E06 TPY mine is 1.123E06 $. Sediment runoff from coal haulage roads can be controlled by the use of small settling ponds at a cost of $20000/pond (Footnote 1135). Assuming that a settling pond is required for each mile of road, 1 settling pond is required. Thus the total capital cost is 1.14E06 $ or 1.14E05 $/yr at 10 percent FCR. Based on a 2E06 TPY coal operation and 57000 T/1.0E12 Btu this is equivalent to 3250 $/1.0E12 Btu. The operating costs is taken as $317580/yr from footnote 1046. Thus for a 2E06 TPY coal operation and 57000 T/1.0E12 Btu this is equivalent to 9051 $/1.0E12 Btu.

9453 From footnote 1046 the capital cost for transportation equipment for a 2E06 TPY mine is 1.12E06 $. Sediment runoff from coal haulage roads can be controlled by the use of settling ponds at a cost of $20000/pond (Footnote 1135). Assuming that a settling pond is required for each mile of road, 7 settling ponds are required. Thus the total capital cost is 1.26E06 $ or 1.26E05 $/yr at 10 percent FCR. Based on a 2E06 TPY coal operation and 41700 T/1.0E12 Btu this is equivalent to 2630 $/1.0E12 Btu. The operating cost is taken as $317580/yr from footnote 1046. Thus for a 2E06 TPY coal operation and 41700 T/1.0E12 Btu this is equivalent to 6622 $/1.0E12 Btu.

9454 Fuel consumption by the haulage trucks amounts to 3003 gal diesel fuel/1.0E12 Btu (footnote 9414). For 5.83E06 Btu/BBL diesel fuel this is equivalent to 4.17E08 Btu/1.0E12 Btu.

9455 From footnote 1046 the capital cost for transportation equipment for a 2E06 TPY mine is 1.12E06 $. Sediment runoff from coal haulage roads can be controlled by the use of small settling ponds at a cost of $20000/pond (Footnote 1135). Assuming that a settling pond is required for each mile of road, 4 settling ponds are required. Thus the total capital cost is 1.20E06 $ or 1.20 E05 $/yr at 10 percent FCR. Based on a 2E06 TPY coal operation and 46200

T/1.0E12 Btu this is equivalent to 2770 $/1.0E12 Btu. The operating cost is taken as $317580/yr from footnote 1046. Thus for a 2E06 TPY coal operation and 46200 T/1.0E12 Btu this is equivalent to 7336 $/1.0E12 Btu.

9456 An arithmetic average of the CSF and SRC processes for the National Average case.

9457 An arithmetic average of transportation numbers for the Northern Appalachian, Central, and Northwest regions.

9458 An arithmetic average of the CSF and SRC processes for the Northwest region.

9459 An arithmetic average of the CSF and SRC process for the Central region.

9460 An arithmetic average of the CSF and SRC processes for the Northern Appalachian region.

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APPENDIX A

LIST OF ABBREVIATIONS

A	Ash
AC	Acre
A/C	Air Conditioner
ALD	Aldehydes
AMNT	Amount
AV	Average
BAAPCD	San Francisco Bay Area Air Pollution Control District
BADCT	Best Available Demonstrated Control Technology
BBL	Barrel(s)
BCF	Billion Cubic Feet (Standard)
BOD	Biological Oxygen Demand
BPH	Barrels per Hour
BPSD	Barrels per Stream Day
BPY	Barrels per Year
BTU	British Thermal Unit
BTUH	BTU per Hour
B-T-X	Benzene Toluene Xylene
C	Cents
CO	Carbon Monoxide
CAP	Capacity
CD	Calendar Day
CF	Cubic Feet
CN/SCN	Cyanide and Thiocyanates
CY	Cubic Yard
D	Day
DIST or DSTL	Distillate
DOT	Department of Transportation
DS	Dissolved Solids
DSCF	Dry Standard Cubic Feet
DSCFM	Dry Standard Cubic Feet per Minute
DWT	Deadweight
E	Equivalent
ELECT	Electricity
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
F	Fahrenheit
FC	Fixed Carbon
FCR	Fixed Charge Rate
FF	and following pages . . .
FT	Foot (Feet)
FPS	Feet Per Second
GAL	Gallon
GAS	Natural Gas
GASO	Gasoline
GM	Gram
GPD	Gallons per Day

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GPM	Gallons per Minute
GR	Grains
HEW	U.S. Department of Health, Education and Welfare
HP	Horsepower
HR	Hour
IN	Inch
KW	Kilowatt
KWH	Kilowatt Hour (Electrical)
L	Liter
LB	Pound
LF	Load Factor
LIRR	Long Island Railroad
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LT	Long Ton
LTS	Long Ton Sulfur
M	Thousand
MCF	Thousand Cubic Feet (Standard)
MEA	Monoethanolomine
MF	Moisture Free
MG	Milligram
MGD	Million Gallons per Day
MI	Mile(s)
MIBK	Methylisobutyl Ketone
MM	Million
MMCF	Million Cubic Feet (Standard)
MMCFD	Million Cubic Feet per Day
MOL	Mole
MPG	Miles per Gallon
MW	Megawatts
NDO	Nondegradable Organics
NGL	Natural Gas Liquids
NMI	Nautical Miles
NO	Number
ODS	Other Dissolved Solids
OST	Office of Science and Technology
P or PC	Percent
PE	Primary Efficiency
PHS	Public Health Service
PLF	Plant Load Factor
PM	Passenger Mile
PPM	Parts per Million
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gage
RESID or RFO	Residual fuel oil
ROM	Run of Mine
S	Sulfur
SCF	Standard Cubic Feet
SF	Square Foot (Feet)
SGC	Stack Gas Cleaning
SH	Short
SI	Square Inch(es)

SNG	Synthetic Natural Gas
SRC	Solvent Refined Coal
S/S	Suspended Solids
T	Tons(s)
TDS	Total Dissolved Solids
TM or TMI	Ton Mile
TPD	Tons per Day
TPY	Tons per Year
TS	Total Solids (Dissolved + Suspended)
USDI	U.S. Department of the Interior
VM	Vehicle Mile
VMA	Volatile Matter
W or WT	Weight
WAL	Weak Ammonia Liquor
YR	Year